filed electronically in docket office on 10/29/09

IN THE TENNESSEE REGULATORY AUTHORITY
AT NASHVILLE, TENNESSEE

IN RE:	)	
	)	
Petition of Piedmont Natural Gas Company, Inc. for Approval of Service Schedule No. 317 and Related Energy Efficiency Programs	)	**DOCKET NO. 09-00104**

RESPONSES AND OBJECTIONS OF THE CONSUMER ADVOCATE TO PIEDMONT'S DISCOVERY REQUEST

Robert E. Cooper, Jr., Attorney General and Reporter for the State of Tennessee, by and through the Consumer Advocate and Protection Division of the Office of the Attorney General ("Consumer Advocate"), pursuant to the Hearing Officer's ruling at the status conference held on June 4, 2008, hereby submits its responses and objections to the first discovery request of Piedmont Natural Gas Company, Inc. ("Piedmont" or "Company").

GENERAL OBJECTIONS

1. The Consumer Advocate objects to the definitions and instructions contained in the Company's interrogatories to the extent that the definitions and instructions attempt to impose on the Consumer Advocate a burden or obligation greater than that required by the *Tennessee Rules of Civil Procedure* and applicable statutes and regulations governing contested case hearings.

2. The Consumer Advocate objects to the interrogatories to the extent they call for information and the production of documents which are protected from disclosure by the attorney-client privilege, the attorney work product doctrine or any other applicable privilege or protection. The Consumer Advocate objects to the data requests to the extent that the Company is attempting to impose on the Consumer Advocate obligations with regard to identification of

privileged documents beyond those required by the *Tennessee Rules of Civil Procedure* and applicable statutes and regulations governing contested case hearings.

3. The Consumer Advocate objects to the Company's interrogatories to the extent they seek information not related to the subject matter involved in this litigation or to the extent they are not reasonably calculated to lead to the discovery of admissible evidence. By providing information in response to these requests, the Consumer Advocate does not concede that such information is relevant, material or admissible in evidence. The Consumer Advocate reserves all rights to object to the use of such information as evidence.

4. The Consumer Advocate objects to the Company's interrogatories to the extent that the Company is attempting to impose on the Consumer Advocate obligations to supplement its responses beyond those required by the *Tennessee Rules of Civil Procedure* and applicable statutes and regulations governing contested case hearings.

5. The Consumer Advocate objects to the Company's interrogatories to the extent that the Company is attempting to require the Consumer Advocate to provide information and produce documents beyond those in its possession, custody or control as that phrase is used in the *Tennessee Rules of Civil Procedure* and applicable statutes and regulations governing contested case hearings.

6. The Consumer Advocate objects to the Company's data requests to the extent they seek information and documents that are readily available through public sources or are in the Company's own possession, custody or control. It is unduly burdensome and oppressive to require the Consumer Advocate to respond or produce documents that are equally available to the Company.

7. The Consumer Advocate's objections and responses to these requests are based on information now known to it. The Consumer Advocate reserves the right to amend, modify or supplement its objections and responses if it learns of new information.

8. The Consumer Advocate's responses to these requests are made without waiving or intending to waive the right to object to the use of any information provided in response to any

subsequent proceeding or trial of this or any other action. The Consumer Advocate's responses to these requests are also not a waiver of any of the foregoing objections or any objections it has made or may make with respect to any similar, related, or future data request, and the Consumer Advocate specifically reserves the right to interpose any objection to further requests notwithstanding any response or lack of objection made in this response.

9. The Consumer Advocate will supplement its responses in accordance with the requirements of state law.

10. The Consumer Advocate expressly incorporates these general objections into its responses set forth below.

Subject to and without waiving any objections stated above the Consumer Advocate responds to the specific requests as follows:

DISCOVERY RESPONSES AND OBJECTIONS

1. State the Consumer Advocate's position on what is the most appropriate mechanism or financial incentive to ensure that Piedmont's financial incentives are aligned with the state's energy conservation policy as set out in 2009 Public Act 531, Section 53.

RESPONSE:

Consistent with the General Objections above, the Consumer Advocate objects to the extent this request seeks privileged information or information protected from disclosure by attorney work product doctrine or other applicable law. The Consumer Advocate's work on this issue is on-going; consequently, it reserves the right to supplement and produce additional information as it becomes available. The Consumer Advocate's analysis in this case is fact intensive and detail oriented. The Consumer Advocate's analysis and opinion(s) are dependent upon information which is in the hands of Piedmont and which has not yet been made available to the Consumer Advocate.

Subject to and without waiving these objections and in an effort to avoid delaying this proceeding the Consumer Advocate responds as follows:

See the *Statement of the Consumer Advocate on Implementing Conservation Measures in Tennessee* filed in Docket 09-00065 on September 25, 2009. Moreover, the subject-matter of this docket, namely the implementation of the General Assembly's new energy conservation policy enumerated in 2009 Public Act 531, Section 53, is controlled by the following:

> The general assembly declares that the policy of this state is that the Tennessee regulatory authority will seek to implement, in appropriate proceedings for each electric and gas utility, with respect to which the authority has rate making authority, a general policy that ensures that utility financial incentives are aligned with helping their customers use energy more efficiently and that provides timely cost recovery and a timely earnings opportunity for utilities associated with cost-effective measurable and verifiable efficiency savings, in a way that sustains or enhances utility customers' incentives to use energy more efficiently.

The new policy neither requires nor forbids decoupling mechanisms to promote conservation. The natural gas industry, collectively, has submitted that the new policy should be implemented on a case by case basis, taking into account the differing operating conditions of the utilities and differing needs of customers and that the Authority should avoid a "one size fits all" policy. *See* the individual comments of Chattanooga Gas Company, Atmos Energy Corporation and Piedmont in Docket 09-00065 filed August 3-4, 2009. Thus, the appropriate mechanism, according to the state's natural gas industry, is a factually intensive and detail oriented subject-matter and dependent upon the circumstances of the individual utility. At this time, the Consumer Advocate's position is reliant upon Piedmont's company specific information and information showing both the short and long term financial impact of the Piedmont's proposal, which is currently not within the record or within the Consumer Advocate's possession.

The Consumer Advocate's position on this issue is to seek a policy which will encourage consumer energy conservation while allowing the utility to continue to have the opportunity to earn a fair return. Piedmont's proposal is a decoupling mechanism which the Company submits fulfills the State's policy. However, given the lack of specific information in the record, the Consumer Advocate is not satisfied at this time Piedmont's proposal is the appropriate policy tool to implement the State's new energy conservation policy.

Proponents of decoupling mechanisms have generally linked the concept of decoupling to energy conservation to the extent gas utilities promote decoupling mechanisms and conservation as one in the same. Decoupling has been described as a way to break the link between sales volume and utility revenues in order to allow a utility to encourage conservation. The theory sounds logical and laudable. However, the practical application of decoupling, as sought by the natural gas industry, has been subject to dispute and controversy. For example, the Iowa Utilities Board conducted an in-depth study of decoupling and rejected the proposal in 2006. Ultimately, the Board concluded the mandatory conservation programs specifically required under Iowa law for over a decade had no impact on the revenues of the utilities, thus decoupling was not needed. A copy of the order is attached at Tab A. In another example, the New Mexico Public Regulation Commission adopted the conclusions of the Hearing Officer rejecting a proposed decoupling mechanism that was characterized as designed to provide a "financial windfall" for utilities rather than making them financially neutral to conservation programs. An excerpt of the Hearing Examiner's order is attached at Tab B.[1]

In Rhode Island, decoupling has been rejected for natural gas consumers. The Commission noted that the financial benefits to the utility from decoupling were well

[1] Complete copies of the Hearing Examiners Ruling and the New Mexico Commission Order adopting the ruling is attached to Mike Chrslyer's Direct Testimony in Docket 07-00105, filed August 22, 2007 and publicly available through the TRA's electronic website.

documented in the record with information showing the utility would have collected an additional $34 million over the preceding four years had the mechanism been in place. However, any benefit accrued by consumers from decoupling would be based on speculation. A copy of the Commission's order is attached at Tab C. *See* pp. 57-72 for discussion and ruling.

In the context of shifting business risk to consumers, North Carolina is an example of a state in which a decoupling mechanism produced large rate increases while insulating Piedmont from economic risk. In 2005, the North Carolina Utilities Commission allowed Piedmont to implement a decoupling mechanism, known as the Customer Utilization Tracker ("CUT"), on an experimental basis. According to a report written by the North Carolina Utilities Commission and submitted to the Joint Legislative Utility Review Committee of the state legislature on October 2, 2008, the CUT produced $99.2 million dollars in additional rates owed to Piedmont by consumers in a three year period. Roughly half of this amount was attributable to price elasticity rather than the effects of the utility conservation program. The remaining half of the CUT's revenues was attributable to weather as the WNA in North Carolina was discontinued when the CUT was adopted. A copy of the report is attached to the Consumer Advocate's *Addendum to the Memorandum in Support of Motion Requesting Permission to Issue More Than Forty Discovery Requests*, filed in this docket on October 13, 2009.

The North Carolina Utilities Commission report states that warmer than usual weather and the effects of Hurricane Katrina and Hurricane Rita on natural gas prices contributed to financial impact of the CUT. The Consumer Advocate would note the impact of weather, natural gas prices and of the aforementioned hurricanes were equally felt in Tennessee. However, at no point during the three year period covered by the North Carolina report did Piedmont file a rate case in Tennessee.

Another example that is notable is in neighboring Virginia. In December of 2008, the Virginia State Corporation Commission ("Virginia Commission") implemented a decoupling mechanism pursuant to a 2008 law, the Natural Gas Conservation and Rate-making Efficiency Act ("Act"), requiring decoupling. Pursuant to the Act, Virginia Natural Gas, Inc. ("VNG") filed a proposed decoupling mechanism which the Virginia Commission approved. The final order issued by the Virginia Commission discusses the concerns and opposition of the Commission's staff regarding the decoupling mechanism, known as the Revenue Normalization Adjustment ("RNA"). A copy of the order is attached at Tab D. The pre-filed testimony of the Virginia Commission Staff which contains their findings is attached at Tab E. The Virginia Commission noted on page 18 of the order that had the RNA been in effect in 2006 and 2007, consumers would have paid more than 5% in additional rates in 2006 and 2007. However, the Act prevented the Commission from considering these concerns. The Authority is this matter has no similar legal constraint.

The decoupling debate has been on-going in Tennessee before the Authority. A decoupling mechanism proposed by Atmos Energy Corporation, which shares the basic framework of Piedmont's proposal, was rejected by the Authority as it removes any incentive for a utility to control fixed costs. Docket 05-00258, *Transcript of Proceedings*, October 26, 2006, pp. 6-7, 13 (*See* also Director Miller's Motion which is attached to the referenced transcript). In addition, Piedmont's decoupling proposal does not account for the additional revenue created by customer growth. The pre-filed written testimony on behalf of the Consumer Advocate concerning the off-setting effect to margin loss per customer, and even to an extent allowing over-earning in revenues and return on equity, from revenue generated from customer growth is publicly available online at the TRA website. See the pre-filed Direct Testimony of Mike

Chrysler in Docket 07-00105 filed on August 22, 2007; See also Rebuttal Testimony of Daniel McCormac in Docket 05-00258 filed on August 18, 2006. Recently, Atmos has acknowledged historical customer growth rates have offset the declining revenue per customer due to conservation while noting that customer growth had declined recently due to the downturn in the economy. *See* the sworn pre-filed Direct Testimony of Mr. Kevin Akers on behalf of Atmos Energy in Docket 08-00197 filed October 15, 2008. On page 4 at lines 1-2, Mr. Akers states historic growth rates have been "sufficient to overcome declining customer usage due to energy conservation and more efficient homes and appliances."

The decoupling debate is not confined to Tennessee or a few other states. See the attached presentation given by Ken Costello, senior economist for the National Regulatory Research Institute at Tab F. Mr. Costello's presentation provides an overview of the national debate on decoupling and examines the arguments both for and against decoupling. Other states have adopted modified decoupling mechanisms or adopted alternatives to decoupling in order to encourage conservation. The Colorado Public Utilities Commission modified a decoupling mechanism in order for both consumers and the utility to share risk and to encourage the utility to control costs. The order is attached at Tab G. *See* pages 11-13. New Jersey has adopted a modified mechanism. The order is attached at Tab H.

2. With respect to the position stated in response to the foregoing data request:

(a) Identify each and every factual basis relied upon by the Consumer Advocate in reaching such position;

RESPONSE:

Consistent with the General Objections above, the Consumer Advocate objects to the extent this request seeks privileged information or information protected from disclosure by attorney work product doctrine or other applicable law. Without waiving the aforementioned

objections, the Consumer Advocate responds as follows: See Response to Request 1. The Consumer Advocate reserves the right to produce more information as it becomes available to it.

(b) Identify each and every legal basis relied upon by the Consumer Advocate in reaching such position;

RESPONSE:

Consistent with the General Objections above, the Consumer Advocate objects to the extent this request seeks privileged information or information protected from disclosure by attorney work product doctrine or other applicable law. Without waiving the aforementioned objections, see Response to Request 1.

(c) Identify each and every witness the Consumer Advocate intends to call to support such position; and

RESPONSE:

The Consumer Advocate, consistent with the General Objections above, the Consumer Advocate objects to the extent that no decision has been made as to what witness will testify on any particular issue in this matter. Without waiving any objection, the Consumer Advocate responds as follows: At this time, it is possible Terry Buckner may provide testimony in support of a modified decoupling mechanism or in support of an alternative proposal. Mr. Buckner's opinion will be based on an analysis of information that is not currently within the possession of the Consumer Advocate, but rather in possession of the Company. The Consumer Advocate has requested this information from Piedmont. In addition, the Consumer Advocate has engaged consultants; however no decision has been made to whether such consultants will be engaged to provide testimony in this docket.

(d) Identify each and every document relating to, or reviewed or relied upon in reaching, such position.

RESPONSE:

Consistent with the General Objections above, the Consumer Advocate objects to the extent this request seeks privileged information or information protected from disclosure by attorney work product doctrine or other applicable law. The Consumer Advocate also objects to this Request as it is currently worded as being unduly broad and burdensome and beyond the scope of reasonably allowable discovery. It is unduly burdensome, unnecessary for the preparation of this Docket and practically unworkable for the Consumer Advocate to be required to produce every document in its possession that relates to the any position it might take in this Docket or that was reviewed by any consultant or other witness it may call in the Hearing on this Docket. The Consumer Advocate will produce for Piedmont all documents relied upon by any witness in formulating any opinion to be expressed by that witness in this Docket as soon as any such witness is finally selected by the Consumer Advocate and their opinions fully formed and decided. The Consumer Advocate is well aware of the compressed time frame that was requested by Piedmont in this Docket and will do its best to finalize the witnesses it intends to call and supplement this response with the required documents as quickly as possible and as far ahead of the deadline for filing Direct Testimony as possible. The Consumer Advocate's ability to finalize its plans for presenting any witnesses in this Docket is at least partially dependent upon receiving the information it seeks from Piedmont in Discovery. The earlier that the requested information is produced for the Consumer Advocate, the earlier that the Consumer Advocate can supplement its response to this request.

Without waiving the aforementioned objections, the Consumer Advocate responds as follows: See Response to Request 1. The Consumer Advocate reserves the right to produce more information as it becomes available to it.

3. If the Consumer Advocate's position is that an alternative mechanism may be more appropriate to fulfill the state's energy conservation policy as set out in 2009 Public Act 531, Section 53, identify the alternative mechanism(s) under the Consumer's Advocate's consideration.

RESPONSE:

See Response and objections to Request 1.

4. With respect to the position and any identified alternative mechanism stated in response to the foregoing data request:

(a) Identify each and every factual basis relied upon by the Consumer Advocate in reaching such position;

RESPONSE:

See Response and objections to Request 1 and 2(a).

(b) Identify each and every legal basis relied upon by the Consumer Advocate in reaching such position;

RESPONSE:

See Response and objections to Request 1 and Request 2(b).

(c) Identify each and every witness the Consumer Advocate intends to call to support such position; and

RESPONSE:

See Response and objections to Request 1 and Request 2(c).

(d) Identify each and every document relating to, or reviewed or relied upon in reaching, such position.

RESPONSE:

See Response and objections to Request 1 and Request 2(d).

5. State the Consumer Advocate's position on what is the most appropriate customer usage level and/or margin to be used as the benchmark for Piedmont's proposed decoupling mechanism.

RESPONSE:

A more recent benchmark for current customer usage and/or margin should be employed if the Authority determines Piedmont's decoupling proposal is the most appropriate mechanism pursuant to 2009 Public Act 531, Section 53. A more recent benchmark should more accurately reflect current economic conditions for the customer and the utility. Moreover, any future gains through energy conservation may be measured and/or accounted for in a more accurate fashion through use of a recent benchmark or one that is known and measurable in the future. However, the Consumer Advocate is awaiting information it has requested from the Company in order to conduct a full analysis. Any benchmark set for an approved decoupling mechanism will determine the immediate rate impact on consumers. At present, there has been no disclosure of the financial impact of Piedmont's proposal through the use of the Company's proposed benchmark.

In December of 2008, the Virginia State Corporation Commission ("Virginia Commission") implemented a decoupling mechanism proposed in Virginia pursuant to a 2008 law, the Natural Gas Conservation and Rate-making Efficiency Act ("Act"), mandating decoupling. Pursuant to the Act, Virginia Natural Gas, Inc. ("VNG") filed a proposed decoupling mechanism which the Virginia Commission approved. The Act required a benchmark from a utility's most recent rate case. The final order issued by the Virginia Commission fully discusses the concerns and opposition of the Commission's staff regarding the decoupling mechanism, known as the Revenue Normalization Adjustment ("RNA"), which used

a 2005 benchmark based on VNG's most recent rate case. The Virginia Commission Staff provided pre-filed testimony of the effect of the RNA on VNG's revenues and increase in the earned return on equity. A copy is attached at Tab D. The Virginia Commission noted on page 18 of the order that had the RNA been in effect in 2006 and 2007, consumers would have paid more than 5% in additional rates in 2006 and 2007. A copy of the order is attached at Tab E. The specific requirements of the Act prevented the Virginia Commission from taking any action to modify the final result of the RNA.

In addition, applying a usage benchmark which is several years old may be unreasonable given the timing of the implementation and results of the conservation programs. The consumer funded effort of the Company to encourage energy conservation is the justification for the proposed decoupling mechanism. However, if conservation programs are not implemented soon thereafter or are simply ineffective, there is no logical support for a usage benchmark based on 2003 data in order to raise rates in 2010. Consumers should not be expected to immediately and retroactively pay Piedmont for margin per customer lost at a 2003 level in 2010 when the promised benefit of utility sponsored conservation is not timely implemented or effective. For example, Piedmont's conservation programs in North Carolina were not fully implemented for almost two years after the decoupling mechanism went into effect. See Comments of Nashville Gas Company, filed in Docket 06-00309, August 8, 2007 at p. 7.

6. With respect to the position stated in response to the foregoing data request:

(a) Identify each and every factual basis relied upon by the Consumer Advocate in reaching such position;

RESPONSE:

Consistent with the General Objections above, the Consumer Advocate objects to the extent this request seeks privileged information or information protected from disclosure by

attorney work product doctrine or other applicable law. Without waiving the aforementioned objections, the Consumer Advocate responds as follows: See Response to Request 5. The Consumer Advocate reserves the right to produce more information as it becomes available to it.

(b) Identify each and every legal basis relied upon by the Consumer Advocate in reaching such position;

RESPONSE:

Consistent with the General Objections above, the Consumer Advocate objects to the extent this request seeks privileged information or information protected from disclosure by attorney work product doctrine or other applicable law. Without waiving the aforementioned objections, see Response to Request 5.

(c) Identify each and every witness the Consumer Advocate intends to call to support such position; and

RESPONSE:

The Consumer Advocate Consistent with the General Objections above, the Consumer Advocate objects to the extent that no decision has been made as to what witness will testify on what issue in this matter. Without waiving any objection, the Consumer Advocate responds as follows: At this time, it is possible Terry Buckner will provide testimony either agreeing with Piedmont's proposed benchmark or proposing an alternative. Any opinion put forth by Mr. Buckner will be based on an analysis of information that is not currently within the possession of the Consumer Advocate, but rather in possession of the Company. The Consumer Advocate has requested this information from Piedmont. In addition, the Consumer Advocate has engaged consultants; however no decision has been made to whether such consultants will be engaged to provide testimony in this docket.

(d) Identify each and every document relating to, or reviewed or relied upon in reaching, such position.

RESPONSE:

Consistent with the General Objections above, the Consumer Advocate objects to the extent this request seeks privileged information or information protected from disclosure by attorney work product doctrine or other applicable law. The Consumer Advocate also objects to this Request as it is currently worded as being unduly broad and burdensome and beyond the scope of reasonably allowable discovery. It is unduly burdensome, unnecessary for the preparation of this Docket and practically unworkable for the Consumer Advocate to be required to produce every document in its possession that relates to the any position it might take in this Docket or that was reviewed by any consultant or other witness it may call in the Hearing on this Docket. The Consumer Advocate will produce for Piedmont all documents relied upon by any witness in formulating any opinion to be expressed by that witness in this Docket as soon as any such witness is finally selected by the Consumer Advocate and their opinions fully formed and decided. The Consumer Advocate is well aware of the compressed time frame that was requested by Piedmont in this Docket and will do its best to finalize the witnesses it intends to call and supplement this response with the required documents as quickly as possible and as far ahead of the deadline for filing Direct Testimony as possible. The Consumer Advocate's ability to finalize its plans for presenting any witnesses in this Docket is at least partially dependent upon receiving the information it seeks from Piedmont in Discovery. The earlier that the requested information is produced for the Consumer Advocate, the earlier that the Consumer Advocate can supplement its response to this request.

Without waiving the aforementioned objections, the Consumer Advocate responds as follows: See Response to Request 5. The Consumer Advocate reserves the right to produce more information as it becomes available to it.

7. State the Consumer Advocate's position on the issue whether Piedmont's earnings should be evaluated prior to the implementation of a decoupling mechanism.

RESPONSE:

Piedmont has not had a rate case since 2003. It is incumbent upon the Authority to examine this issue, prior to making a determination as to the appropriate mechanism to carry out 2009 Public Act 531, Section 53. Moreover, the TRA must still determine whether this is an appropriate proceeding under 2009 Public Act 531, Section 53. Under Tennessee law, rates are required to be just and reasonable. The decoupling proposal of Piedmont effectively ends the concept of "regulatory lag" in traditional rate-making for residential consumers, the rates of which are already adjusted for weather, the cost of natural gas and uncollectible accounts.

Moreover, an examination of utility earnings in the context of decoupling is essential. The Iowa Utilities Board conducted an in-depth study of decoupling and rejected the proposal in 2006. Ultimately, the Board concluded the mandatory conservation programs specifically required under Iowa law for over a decade had no impact on the revenues of the utilities, thus decoupling was not needed. A copy of the order is attached with those documents addressing Response to Request 1.

In the context of the revenue produced by decoupling, such mechanisms have been shown to increase utility earnings. In December of 2008, the Virginia State Corporation Commission ("Virginia Commission") implemented a decoupling mechanism proposed in Virginia pursuant to a 2008 law, the Natural Gas Conservation and Rate-making Efficiency Act

("Act"), requiring decoupling. Pursuant to the Act, Virginia Natural Gas, Inc. ("VNG") filed a proposed decoupling mechanism which the Virginia Commission approved. The final order issued by the Virginia Commission fully discusses the concerns and opposition of the Commission's staff regarding the decoupling mechanism, known as the Revenue Normalization Adjustment ("RNA"). Testimony filed by the Virginia Commission Staff noted on page 18 of the order that had the RNA been in effect in 2006 and 2007, consumers would have paid more than 5% in additional rates in 2006 and 2007 while VNG's return on equity earned, rather than authorized, would increase. A copy of the Virginia Commission Staff pre-filed testimony is attached at Tab E.

8. With respect to the position stated in response to the foregoing data request:

(a) Identify each and every factual basis relied upon by the Consumer Advocate in reaching such position;

RESPONSE:

Consistent with the General Objections above, the Consumer Advocate objects to the extent this request seeks privileged information or information protected from disclosure by attorney work product doctrine or other applicable law. Without waiving the aforementioned objections, the Consumer Advocate responds as follows: See Response to Request 1, Request 6(c) and 7. The Consumer Advocate reserves the right to produce more information as it becomes available to it.

(b) Identify each and every legal basis relied upon by the Consumer Advocate in reaching such position;

RESPONSE:

Consistent with the General Objections above, the Consumer Advocate objects to the extent this request seeks privileged information or information protected from disclosure by

attorney work product doctrine or other applicable law. Without waiving the aforementioned objections, see Response to Request 7.

(c) Identify each and every witness the Consumer Advocate intends to call to support such position; and

RESPONSE:

The Consumer Advocate Consistent with the General Objections above, the Consumer Advocate objects to the extent that no decision has been made as to what witness will testify on any particular issue in this matter. Without waiving any objection, the Consumer Advocate responds as follows: At this time, it is possible Terry Buckner may provide testimony regarding this issue. Any opinion offered put forth by the Consumer Advocate will be based on an analysis of information that is not currently within the possession of the Consumer Advocate, but rather in possession of the Company. The Consumer Advocate has requested this information from Piedmont. In addition, the Consumer Advocate has engaged consultants; however no decision has been made to whether such consultants will be engaged to provide testimony in this docket.

(d) Identify each and every document relating to, or reviewed or relied upon in reaching, such position.

RESPONSE:

Consistent with the General Objections above, the Consumer Advocate objects to the extent this request seeks privileged information or information protected from disclosure by attorney work product doctrine or other applicable law. The Consumer Advocate also objects to this Request as it is currently worded as being unduly broad and burdensome and beyond the scope of reasonably allowable discovery. It is unduly burdensome, unnecessary for the preparation of this Docket and practically unworkable for the Consumer Advocate to be required to produce every document in its possession that relates to the any position it might take in this Docket or that was reviewed by any consultant or other witness it may call in the Hearing on this

Docket. The Consumer Advocate will produce for Piedmont all documents relied upon by any witness in formulating any opinion to be expressed by that witness in this Docket as soon as any such witness is finally selected by the Consumer Advocate and their opinions fully formed and decided. The Consumer Advocate is well aware of the compressed time frame that was requested by Piedmont in this Docket and will do its best to finalize the witnesses it intends to call and supplement this response with the required documents as quickly as possible and as far ahead of the deadline for filing Direct Testimony as possible. The Consumer Advocate's ability to finalize its plans for presenting any witnesses in this Docket is at least partially dependent upon receiving the information it seeks from Piedmont in Discovery. The earlier that the requested information is produced for the Consumer Advocate, the earlier that the Consumer Advocate can supplement its response to this request.

Without waiving the aforementioned objections, See Response to Request 7.

9. State the Consumer Advocate's position on whether the implementation of a decoupling mechanism lowers the business risk for Piedmont, thereby justifying an adjustment to its rate of return.

RESPONSE:

The Consumer Advocate submits that if consumers use less natural gas for any reason, Piedmont's proposed decoupling mechanism will allow the Company to raise the bills of consumers. Thus, the mechanism has the effect of guaranteeing revenues from residential consumers and shielding Piedmont from declining revenue for any economic or business reason. This has the effect of shifting business risk from the utility to consumers. This principle has been recognized in other states in terms of decoupling. This principle has been recognized and quantified by an expert testifying on behalf of Chattanooga Gas Company. *See* Pre-filed Direct Testimony of Dr. Roger A. Morin filed in TRA Docket 06-00175 on June 30, 2006.

In Connecticut, decoupling was rejected. In doing so, the Department of Public Utility Control stated that approval of a decoupling mechanism would require at least a 100 basis point reduction to the ROE to provide the commensurate risk compensation to consumers. A copy of the order is attached at Tab I. *See* pages 90-91. In Illinois, a decoupling mechanism was approved. However, based on the risk reduction of the mechanism, the Illinois Commerce Commission reduced ROE by ten basis points for a gas utility. A copy of the order is attached at Tab J. *See* page 101. The New York Public Service Commission adopted a decoupling mechanism, but also adjusted the ROE by 10 basis points to reflect the lower business risk to the utility. A copy of this order is attached Tab K. *See* pages 32-34. When decoupling mechanisms have been approved for electric utilities, state commissions have adjusted the ROE. *See* copies of orders from Vermont at Tab L and the District of Columbia and Tab M.

10. With respect to the position stated in response to the foregoing data request:

(a) Identify each and every factual basis relied upon by the Consumer Advocate in reaching such position;

RESPONSE:

Consistent with the General Objections above, the Consumer Advocate objects to the extent this request seeks privileged information or information protected from disclosure by attorney work product doctrine or other applicable law. Without waiving the aforementioned objections, the Consumer Advocate responds as follows: See Response to Request 9. The Consumer Advocate reserves the right to produce more information as it becomes available to it.

(b) Identify each and every legal basis relied upon by the Consumer Advocate in reaching such position;

RESPONSE:

Consistent with the General Objections above, the Consumer Advocate objects to the extent this request seeks privileged information or information protected from disclosure by

attorney work product doctrine or other applicable law. Without waiving the aforementioned objections, the Consumer Advocate responds as follows: See Response to Request 9. The Consumer Advocate reserves the right to produce more information as it becomes available to it.

(c) Identify each and every witness the Consumer Advocate intends to call to support such position; and

RESPONSE:

The Consumer Advocate Consistent with the General Objections above, the Consumer Advocate objects to the extent that no decision has been made as to what witness will testify on any particular issue in this matter. Without waiving any objection, the Consumer Advocate responds as follows: Any opinion offered by the Consumer Advocate will be based on an analysis of information that is not currently within the possession of the Consumer Advocate, but rather in possession of the Company. The Consumer Advocate has requested this information from Piedmont. In addition, the Consumer Advocate has engaged consultants; however no decision has been made to whether such consultants will be engaged to provide testimony in this docket. The Consumer Advocate reserves the right to supplement this response as information becomes available to it.

(d) Identify each and every document relating to, or reviewed or relied upon in reaching, such position.

RESPONSE:

Consistent with the General Objections above, the Consumer Advocate objects to the extent this request seeks privileged information or information protected from disclosure by attorney work product doctrine or other applicable law. The Consumer Advocate also objects to this Request as it is currently worded as being unduly broad and burdensome and beyond the scope of reasonably allowable discovery. It is unduly burdensome, unnecessary for the preparation of this Docket and practically unworkable for the Consumer Advocate to be required

to produce every document in its possession that relates to the any position it might take in this Docket or that was reviewed by any consultant or other witness it may call in the Hearing on this Docket. The Consumer Advocate will produce for Piedmont all documents relied upon by any witness in formulating any opinion to be expressed by that witness in this Docket as soon as any such witness is finally selected by the Consumer Advocate and their opinions fully formed and decided. The Consumer Advocate is well aware of the compressed time frame that was requested by Piedmont in this Docket and will do its best to finalize the witnesses it intends to call and supplement this response with the required documents as quickly as possible and as far ahead of the deadline for filing Direct Testimony as possible. The Consumer Advocate's ability to finalize its plans for presenting any witnesses in this Docket is at least partially dependent upon receiving the information it seeks from Piedmont in Discovery. The earlier that the requested information is produced for the Consumer Advocate, the earlier that the Consumer Advocate can supplement its response to this request.

Without waiving the aforementioned objections, see Response to Request 9. The Consumer Advocate reserves the right to supplement this request as information becomes available and an analysis is performed

(e) Identify what method or evaluation tools the Consumer Advocate contends should be utilized to quantify an adjustment to Piedmont's rate of return and why such methods or tools are appropriate.

RESPONSE:

Any opinion offered by the Consumer Advocate will be based on an analysis of information that is not currently within the possession of the Consumer Advocate, but rather in possession of the Company. The Consumer Advocate has requested this information from Piedmont. The Consumer Advocate reserves the right to supplement this request as information becomes available and an analysis is performed.

11. State the Consumer Advocate's position on the issue whether Piedmont should be required to meet specific, verifiable, measurable energy efficiency goals and/or benchmarks for any approved conservation programs.

RESPONSE:

The Consumer Advocate would submit that specific, verifiable, measureable energy efficiency goals and/or benchmarks are essential to the success of any conservation program. Utility conservation programs are the lynch pin of most, if not all, decoupling proposals. If conservation programs are not cost-effective, producing verifiable and measurable results, then there is simply no logical justification for a decoupling mechanism. Further, Piedmont's proposal in this matter includes mandatory consumer funding of conservation programs. If funds from consumers are collected for these programs, they must produce cost-effective, verifiable and measurable results. In essence, as an expense category, such expenditures must be prudent in the context of just and reasonable rates.

12. With respect to the position stated in response to the foregoing data request:

(a) Identify each and every factual basis relied upon by the Consumer Advocate in reaching such position;

RESPONSE:

Consistent with the General Objections above, the Consumer Advocate objects to the extent this request seeks privileged information or information protected from disclosure by attorney work product doctrine or other applicable law. Without waiving the aforementioned objections, the Consumer Advocate responds as follows: See Response to Request 11. The Consumer Advocate reserves the right to produce more information as it becomes available to it.

(b) Identify each and every legal basis relied upon by the Consumer Advocate in reaching such position;

RESPONSE:

Consistent with the General Objections above, the Consumer Advocate objects to the extent this request seeks privileged information or information protected from disclosure by attorney work product doctrine or other applicable law. Without waiving the aforementioned objections, the Consumer Advocate responds as follows: See Response to Request 11. The Consumer Advocate reserves the right to produce more information as it becomes available to it.

(c) Identify each and every witness the Consumer Advocate intends to call to support such position; and

RESPONSE:

The Consumer Advocate, consistent with the General Objections above, the Consumer Advocate objects to the extent that no decision has been made as to what witness will testify on any particular issue in this matter. Without waiving any objection, the Consumer Advocate responds as follows: At this time, it is possible Terry Buckner may provide testimony in support of Piedmont's conservation programs or in support of alternative conservation measures or modifications. Any opinion offered by the Consumer Advocate will be based on an analysis of information that is not currently within the possession of the Consumer Advocate, but rather in possession of the Company. The Consumer Advocate has requested this information from Piedmont. In addition, the Consumer Advocate has engaged consultants; however no decision has been made to whether such consultants will be engaged to provide testimony in this docket.

(d) Identify each and every document relating to, or reviewed or relied upon in reaching, such position.

RESPONSE:

Consistent with the General Objections above, the Consumer Advocate objects to the extent this request seeks privileged information or information protected from disclosure by attorney work product doctrine or other applicable law. The Consumer Advocate also objects to

this Request as it is currently worded as being unduly broad and burdensome and beyond the scope of reasonably allowable discovery. It is unduly burdensome, unnecessary for the preparation of this Docket and practically unworkable for the Consumer Advocate to be required to produce every document in its possession that relates to the any position it might take in this Docket or that was reviewed by any consultant or other witness it may call in the Hearing on this Docket. The Consumer Advocate will produce for Piedmont all documents relied upon by any witness in formulating any opinion to be expressed by that witness in this Docket as soon as any such witness is finally selected by the Consumer Advocate and their opinions fully formed and decided. The Consumer Advocate is well aware of the compressed time frame that was requested by Piedmont in this Docket and will do its best to finalize the witnesses it intends to call and supplement this response with the required documents as quickly as possible and as far ahead of the deadline for filing Direct Testimony as possible. The Consumer Advocate's ability to finalize its plans for presenting any witnesses in this Docket is at least partially dependent upon receiving the information it seeks from Piedmont in Discovery. The earlier that the requested information is produced for the Consumer Advocate, the earlier that the Consumer Advocate can supplement its response to this request.

Without waiving the aforementioned objections, See Response to Request 11 and comments and reports contained in Docket 06-00309. Further, the Consumer Advocate's investigation in this matter is on-going. No specific, verifiable, measurable energy efficiency goals have been identified. The Consumer Advocate has requested pertinent information regarding the proposed conservation program from the Company in order to evaluate the need for and scope of specific, verifiable, measurable energy efficiency goals.

13. Identify each and every specific, verifiable, measurable energy efficiency goals that the Consumer Advocate's contends Piedmont should be required to meet for any approved the benchmark for Piedmont's proposed decoupling mechanism.

RESPONSE:

See Response to Request 11. Further, the Consumer Advocate's investigation in this matter is on-going. No specific, verifiable, measurable energy efficiency goals have been identified. The Consumer Advocate has requested pertinent information regarding the proposed conservation program from the Company in order to evaluate the need for and scope of specific, verifiable, measurable energy efficiency goals. The Consumer Advocate reserves the right to supplement this request as information becomes available and an analysis is performed.

Respectfully Submitted,

ROBERT E. COOPER, JR., BPR # 10934
Attorney General and Reporter

RYAN L. MCGEHEE, BPR #025559
Assistant Attorney General
C. SCOTT JACKSON, BPR# 011005
Senior Counsel
Office of the Attorney General
Consumer Advocate and Protection Division
P.O. Box 20207
Nashville, Tennessee 37202-0207
Telephone: (615) 532-5512
Fax: (615) 532-2910

Dated: October 26, 2009.

CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the foregoing foregoing was served via U.S. Mail or electronic mail upon:

Jane Lewis-Raymond
Piedmont Natural Gas Company, Inc.
P.O. Box 33068
Charlotte, NC 28233

R. Dale Grimes
Bass, Berry & Sims PLC
315 Deaderick Street, Suite 2700
Nashville, TN 37238-3001

James H. Jefferies IV
Moore & Van Allen PLLC
100 North Tryon Street, Suite 4700
Charlotte, NC 28202-4003

This the 26 day of October, 2009.

Ryan L. McGehee
Assistant Attorney General

ATTACHMENT A

Exhibit 2

STATE OF IOWA

DEPARTMENT OF COMMERCE

UTILITIES BOARD

IN RE: INQUIRY INTO THE EFFECT OF REDUCED USAGE ON RATE-REGULATED NATURAL GAS UTILITIES	DOCKET NO. NOI-06-1

ORDER ADDRESSING ISSUES AND CLOSING DOCKET

(Issued December 18, 2006)

On February 9, 2006, the Utilities Board (Board) initiated an inquiry into the effect of reduced natural gas usage resulting from increased energy efficiency and other factors over the next five years on the non-gas revenues of Iowa's rate-regulated natural gas utilities. The Board indicated that Iowa had joined with seven other states, Michigan, Minnesota, Missouri, Wisconsin, Ohio, Illinois, and Indiana, to form the Joint Natural Gas Price Reduction Initiative (JNGPRI) to support regional and individual state actions to create downward pressure on natural gas prices by reducing demand for natural gas by 5 percent over the next five years. The Board indicated that the states recognized that the high cost of natural gas created a financial hardship on many consumers and represented millions of dollars exported from these state economies.

The Board stated that the inquiry would investigate the potential effects of this initiative and other factors in reducing natural gas usage, the resulting effect on regulated non-gas utility revenues, and would consider whether traditional regulation

is flexible enough to address these effects or whether alternative mechanisms or approaches, such as a decoupling mechanism to reduce the influence of sales volumes on utility earnings, might be appropriate. The Board presented a set of initial questions in the February 9, 2006, order for participants to address. Responses to the questions were filed by the Consumer Advocate Division of the Department of Justice (Consumer Advocate), Atmos Energy Corporation (Atmos), the Iowa Environmental Council (IEC), Interstate Power and Light Company (IPL), MidAmerican Energy Company (MidAmerican), Ag Processing Inc (AGP), the Iowa Industrial Energy Group (IIEG), and Aquila, Inc., d/b/a Aquila Networks (Aquila). As part of the inquiry, the Board contracted with the Regulatory Assistance Project (RAP) to conduct a workshop on May 10, 2006, addressing mechanisms considered in other jurisdictions to resolve these issues.

On July 11, 2006, the Board issued an order requesting responses to additional questions. The Board indicated that it had reviewed the initial comments, RAP presentation, and the discussions at the workshop and, based upon that information, the Board had questions about some of the mechanisms that were discussed. AGP, Consumer Advocate, MidAmerican, IPL, IIEG, and Aquila filed additional comments.

In considering whether a decoupling mechanism or similar system should be adopted in Iowa, the Board is faced with two important public policy concerns. First, there is the public policy goal of reducing usage of natural gas by individual customers with the result that overall usage in Iowa, and nationally, is reduced.

Second, there is the requirement under public utility regulation that a utility be given a reasonable opportunity to earn the return authorized by the regulatory agency. In many states these two public policy concerns have been found to be in conflict and various mechanisms to decouple sales of natural gas from a utility's revenues have been proposed to alleviate the tension between the two policies.

Based upon the information reviewed by the Board in this docket, the tension between energy efficiency and Iowa natural gas utilities' opportunity to earn their authorized rate of return does not appear to be a substantial problem in Iowa. Iowa utilities have been participating in energy efficiency plans since before 1990 without substantial adverse effects on earnings. In that year, Iowa established a statutory goal in Iowa Code § 473.3 to "more efficiently utilize energy resources . . . to decrease the state's dependence on energy resources from outside the state by reducing the amount of energy used." This goal was to be implemented through the development of programs that promote energy efficiency and energy conservation by all Iowans.

To meet this statutory goal, the Board developed rules and procedures for planning and implementing energy efficiency programs by Iowa public utilities and has approved several rounds of energy efficiency plans for rate-regulated utilities, most recently in 2003. The energy and peak capacity saved by investor-owned utility energy efficiency programs over the past 15 years have resulted in a cumulative reduction in natural gas usage through 2005 of about 7 million MCF, or about 6.6 percent of annual retail natural gas sales. By 2005, total customer retail cost savings

resulting from these cumulative changes in energy use amounted in 2005 to about $80 million in natural gas costs. From this, the Board concludes that Iowa utilities have not been unable to engage in meaningful energy efficiency programs because of concern about their earnings.

The Board is committed to the continuation of the aggressive energy efficiency programs already in place and to the development of new plans to further increase savings to customers and reduced natural gas consumption from increased energy efficiency. This increase in energy efficiency programs by utilities and their customers may have an adverse effect on the ability of rate-regulated utilities to have a reasonable opportunity to earn their authorized rates of return, potentially creating a disincentive to utility participation in these programs.

Other jurisdictions that lack the energy efficiency mandate and history of Iowa have adopted decoupling mechanisms. The Board believes this may be appropriate in situations where reduced natural gas usage resulting from energy efficiency programs may aversely affect earnings. When this situation exists, utilities should be able to propose appropriate mechanisms to provide the utilities with a reasonable opportunity to earn their authorized rates of return in spite of reduced sales volumes. The information reviewed in this inquiry does not demonstrate that situation for Iowa utilities to date, but the Iowa utilities in this docket have nonetheless proposed several different alternatives solutions to declining customer usage, perhaps in anticipation of increased emphasis on energy efficiency programs. The suggested

changes included rate design proposals, incentive mechanisms, and automatic rate adjustments, among other things.

One reason that Iowa utilities may not be subject to the same pressures as utilities in other jurisdictions is that the Board allows recovery of the costs associated with approved energy efficiency plans through an automatic adjustment mechanism for natural gas utilities, the Energy Efficiency Cost Recovery (EECR). This pass through of energy efficiency plan costs alleviates some of the disincentive for utilities to promote greater energy efficiency by customers. The Board recognizes that the EECR may not be a complete answer, however, as it compensates utilities for expenditures but does not address the possible adverse effect reduced energy consumption might have on utility returns.

Information reviewed by the Board in this docket concerning Iowa natural gas utilities shows that Iowa rate-regulated utilities have experienced a reduction in average customer usage over the past ten years, as have utilities in other jurisdictions. The information does not indicate that reduced usage has substantially adversely affected utilities' net operating income. The Board examined annual reports from 1995 to 2005 for each of the four rate-regulated natural gas utilities showing the average residential usage by utility from 1995 to 2005, the net operating income of each utility over the same period, and the relationship between weather and total purchases of natural gas by utility over the same period. The data shows that average residential customer usage has declined and total purchases have declined while winter weather has generally been warmer than normal over the past

several years. The data does not show a direct correlation between net operating income and declining customer usage as a result of energy efficiency programs to date.

However, it is unclear whether updated, more aggressive programs will change this situation. Each utility is likely to be affected differently, so each utility's situation should be considered separately. Separate consideration for each utility will allow the Board to determine whether any decline in net operating income is the result of a decline in customer usage due to increased energy efficiency or some other factor.

The Board believes decoupling mechanisms or rate design changes are appropriate when the circumstances support the need for such mechanisms. Some of the decoupling mechanisms that have been adopted in other jurisdictions are similar to the automatic adjustment mechanisms that are provided for pursuant to Iowa Code § 476.6(8). The Board has adopted these types of mechanisms to respond to costs that the utility management has little or no control over, that are volatile (i.e., subject to sudden and important changes in level), and that are an important factor in determining the total cost of service to customers. Under this statutory authority, the Board has adopted automatic adjustments for the purchase of natural gas, the purchased gas adjustment (PGA), and for fuel costs for electricity, the energy adjustment clause (EAC). The Board has also adopted an automatic adjustment mechanism, the EECR, pursuant to Iowa Code § 476.6(16), that

authorizes the recovery of the costs of implementing an energy efficiency plan approved by the Board.

At this time, the Board considers the standards established for the automatic adjustment mechanisms listed above to be the appropriate standards for considering whether there is a need for an automatic adjustment mechanism to compensate a utility for reduced customer usage because of increased energy efficiency. The decoupling mechanisms reviewed by the Board in this docket did not effectively identify the effect of increased energy efficiency by customers and often included other factors in the determination of when an adjustment would be made. The Board understands there may be a need by a utility to remove any disincentives that would limit promotion of increased energy efficiency, however, decoupling mechanisms that adjust for other factors may go beyond what the Board considers to be reasonable.

A review of the decoupling mechanisms suggested by the participants shows there was not a general consensus supporting use of decoupling mechanisms or a single type of mechanism. Since there was a lack of consensus, the Board will not attempt to establish a single, specific automatic adjustment mechanism that would be applicable to all of the rate-regulated utilities. Instead, the Board will encourage each utility to review its circumstances and determine if increased energy efficiency and reduced customer usage have caused, or are likely to cause, a decline in net operating income. If a relationship is shown, the utility should develop a proposal that may include an automatic adjustment mechanism, rate design change, or other solution that it considers reasonable to address the situation and should make the

appropriate filing with the Board for consideration in an appropriate proceeding. Since each rate-regulated utility will make a separate determination of whether it should make a filing and those filings will be considered in separate dockets, no further action is required in this docket. Docket No. NOI-06-1 will therefore be closed.

IT IS THEREFORE ORDERED:

Docket No. NOI-06-1 is closed.

UTILITIES BOARD

/s/ John R. Norris

/s/ Diane Munns

ATTEST:

/s/ Judi K. Cooper
Executive Secretary

/s/ Curtis W. Stamp

Dated at Des Moines, Iowa, this 18th day of December, 2006.

ATTACHMENT B

Exhibit 3

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF NEW MEXICO FOR A REVISION TO ITS RATES, RULES, AND CHARGES PURSUANT TO ADVICE NOTICE NOS. 755 AND 756, PUBLIC SERVICE COMPANY OF NEW MEXICO, Petitioner.	)	Case No. 06-00210-UT

RECOMMENDED DECISION OF THE HEARING EXAMINER

Lee W. Huffman, Hearing Examiner for this case, submits this Recommended Decision to the New Mexico Public Regulation Commission ("Commission" or "NMPRC") pursuant to 17.1.2.32.E(4) and 17.1.2.39.B NMAC. The Hearing Examiner recommends that the Commission adopt the following Statement of the Case, discussion, findings of fact, conclusions of law and decretal paragraphs in its Final Order. A Table of Contents has been included for convenience of reference.

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2. PNM's Decoupling Proposal

PNM proposes in this case to break the historic link between its sales volumes and the revenues it receives. It would do so on a per customer basis. Tr. 12/14/06, pp.85, 158-159. Quite simply, if an existing residential customer reduces their natural gas use by half, under PNM's decoupling proposal that customer would still pay the same full amount to PNM that the customer paid when PNM delivered twice as much gas to the customer. Tr. 12/14/06, p.233. The customer would always pay for the actual amount of natural gas used at the market price[16], but their individual conservation efforts would not affect the 1/3 of their bill that covers PNM's services. PNM's revenues and profits depend entirely on its authorized charges for these delivery (transmission and distribution) services.

As it stands now, about one third of a typical customer's bill is for the basic services PNM provides of delivering natural gas through its system to its customers. PNM's proposal, variously called decoupling or a Consumption Normalization Adjustment ("CNA") would be placed in its rates via proposed Rate Rider 16 ("RR 16"). It would only apply to PNM's residential and small commercial customers. It would not apply to PNM's other rate classes, such as large commercial and industrial customers. These large customers are NMIEC's membership and even though decoupling would not apply to its members, NMIEC's primary focus in this case is its opposition to decoupling.

[16] PNM does not make any profit on the sale of natural gas to its retail customers. PNM charges its customers exactly what PNM pays for the gas. There is no markup, no profit, just an exact pass-through of PNM's costs. The mechanism for this arrangement is the Purchased Gas Adjustment Clause or PGAC. Typically, the gas charge or commodity portion is about 2/3 of a residential customer's bill. The commodity price of natural gas is not regulated and reflects the operation of market forces. Tr. 12/14/06, p.174.

Every intervenor group in this case that represents PNM's customers opposed decoupling or RR 16. They are the AG, NNSA, CANM, NMIEC (all of whom testified against the proposal) and UNM, whose witness did not testify concerning decoupling, but UNM argued against decoupling in its Briefs. NRDC/SWEEP and Staff supported decoupling, but Staff expressed concern about the legal issues of whether RR 16 constitutes retroactive ratemaking and whether it is consistent with the prior hearing requirement before changing rates of NMSA 1978, Section 62-8-7(E). Also, Staff suggested that the reduction of risk for PNM that decoupling would cause should be reflected, if decoupling is approved, in PNM's allowed return on equity.

In support of its decoupling proposal, PNM relies in large measure on the Efficient Use of Energy Act ("EUE"). NMSA 1978, Section 62-17-1, *et seq*. (2005). The Act provides in Section 62-17-3 (emphasis supplied) that: "It is the policy of the Efficient Use of Energy Act that **public utilities ... include cost-effective energy efficiency and load management investments in their energy resource portfolios and that any regulatory disincentives that may exist to public utility investments in cost-effective energy efficiency and load management are eliminated."**

The EUE requires that the Commission determine whether there are any regulatory disincentives to such utility investments and if the Commission finds that there are, the Commission is further required to eliminate such regulatory disincentives. **"The commission shall identify any disincentives or barriers that may exist for public utility expenditures on energy efficiency and load management and, if found, ensure that they are eliminated in order that public utilities are financially**

neutral in their preference for acquiring demand or supply-side utility resources." NMSA 1978, Section 62-17-5(F) (2005) (emphasis supplied).

The Commission has not made any findings that such barriers or disincentives exist. PNM and NRDC ask the Commission to do so in this case. Before reaching that question, we turn to PNM's central position concerning decoupling.

PNM claims that its decoupling proposal is necessary[17] to carry out the purposes of the Efficient Use of Energy Act. The policy of the EUE requires PNM, and other utilities (gas and electric), to make certain types of energy efficiency and load management investments and it requires the Commission to first determine if any disincentives or barriers exist to such utility investments, and second, if found, to eliminate them so "public utilities are financially neutral in their preference for acquiring demand or supply-side utility resources."

PNM argues it needs decoupling to eliminate the disincentive it now has to reduce its sales volumes. PNM depends on the sale of a certain volume of natural gas to recover its fixed costs. The customer charge for residential customers covers about 45% of PNM's fixed costs and is imposed regardless of the amount of gas used. Tr. 12/14/06, p.162. PNM points out that if it invests in energy efficiency or load management programs, customers will reduce their natural gas use and thus reduce PNM's revenues, recovery of fixed costs and consequently its profits. PNM's primary witness concerning decoupling, Mr. Feingold, testified that "proposed Rate Rider No. 16 should be viewed as a means to eliminate disincentives associated with PNM's efforts

[17] PNM's decoupling witness agreed that RR 16, PNM's proposal, is "not the only one, but it's the most effective one to eliminate the ... disincentive which is the throughput incentive that a utility has." Tr. 12/14/06, p.158.

to promote energy efficiency and conservation programs such as its Residential Gas Energy Efficiency Program...." PNM Exhibit 15 (Feingold Direct), p.5.

PNM Vice President Melvin Christopher explained PNM's claim of an existing incentive for increasing sales volumes (or throughput of natural gas) and corresponding disincentive to invest in programs that reduce customers' use of gas.

> With throughput we make more money. With a decrease in throughput it hits our earnings and we don't make money. That is a significant disincentive. The efficient use of energy act is encouraging a reduction in usage by customers and encouraging the company or requiring the company to put into place programs that will lead to a decrease in throughput. That is a clear disincentive and a clear disincentive for the company....

Tr. 12/13/06, p.64.

As written, RR 16 would protect PNM from any reduction in consumption due to ratepayer actions, including those completely unrelated to PNM's energy efficiency programs such as customer reaction to the increased price of gas, general economic conditions, and customer actions such as turning down the thermostat. NMIEC Exhibit 3 (Dirmeier Direct), pp.11-12.

PNM witness Feingold admits that his decoupling proposal, RR 16, will adjust rates on a monthly basis for fluctuations in PNM's actual gas volumes which are "caused primarily by the energy efficiency and conservation efforts of [PNM's] customers and variations from 'normal' weather." PNM Exhibit 15 (Feingold Direct), p.4. PNM's own recent conservation and efficiency efforts are not even one of the causes of the significant decline in gas use per customer over the last ten years, because PNM had no gas efficiency program in place during this time. Tr. 12/14/06, pp.141-142.

As a result, PNM would be automatically compensated for any reduction in per customer use, including the customer response to high gas prices. Tr. 12/14/06, p.150. The EUE was enacted, NNSA, NMIEC, the AG and UNM argue, to eliminate disincentives to public utility expenditures on energy efficiency and load management programs, not to give PNM an automatic rate adjustment mechanism to compensate it for lost revenues no matter what caused the loss.

Mr. Feingold admitted at the hearing that the need for his revenue decoupling mechanism had two causes, "the margin losses associated with declining use per customer and the need to eliminate the throughput incentive...." Tr. 12/14/06, p.222. Despite selling less natural gas per customer, PNM's overall revenues have increased along with customer growth. Between 1998 and 2003, PNM added over 37,000 new customers and its total revenues from residential customers exceeded its corresponding rate case revenue by over $34 million. *Id.*

PNM witness Feingold states that Rate Rider 16 is the recommended ratemaking solution to ensure PNM's financial performance is not negatively impacted by the actions of its customers in response to its Residential Gas Efficiency Program and additional energy efficiency program it expects to implement in the future. PNM Exhibit 15 (Feingold Direct), p.5. But PNM witness Christopher acknowledges that the purpose of the decoupling mechanism is to compensate PNM when "customers practice conservation, implement energy efficiency measures, or consume less gas in response to warmer winter temperatures..." PNM Exhibit 1 (Christopher Direct), p.8. And PNM witness Fernald recognized that the "first and most likely contributor to reduced

consumption is the very sharp increase in natural gas prices...." PNM Exhibit 25 (Fernald Direct), p.35.

PNM's solution to its posited disincentive is overbroad. Assuming PNM has such a disincentive, and assuming the Commission were to agree and require its elimination in this case, the EUE requires the elimination of "any disincentives or barriers" to the required utility investments. The Act does not require, or even contemplate, insulating PNM's revenue recovery from any and all causes. The EUE mentions "utility expenditures on energy efficiency and load management." Section 62-17-5(F). It requires, if a disincentive is found, that utilities be made financially neutral as to whether they prefer "demand or supply-side utility resources." The Act does not require that they receive the same amount of money from a customer who chooses to use less gas.

The scope of PNM's decoupling proposal is remarkably broad. At the hearing, PNM witness Feingold agreed that his Rate Rider 16 is much broader than protecting PNM's financial performance from customer response to PNM's residential energy efficiency program. Tr. 12/14/06, p.142. Decoupling protects PNM regardless of why per customer revenues decrease. *Id.* at pp.160-161. Mr. Feingold agreed that the EUE does not mention decoupling or protecting a utility from weather risk (*Id.* at p.68), or lost sales due to higher gas prices or fuel switching. *Id.* at pp.70-71. Even so, his proposed solution of removing the throughput incentive is broad enough, in his opinion, to protect PNM from all such risks.

"I said those words are not in the Act, but my reading of the removing of disincentives supports the fact that the throughput incentive, which is the utility's ability to earn more or generate more revenues as volumes increase, is something that needs

to be removed before a utility can go forward aggressively with energy efficiency and conservation programs. **So to me that throughput incentive embodies all factors related to use per customer.**" Id. at p.69. (emphasis supplied). Mr. Feingold's focus is on use per customer, and his decoupling proposal "Rate Rider 16 is premised on use per customer." Id. at p.85. His premise finds no support in the EUE.

This single-minded focus on use per customer ignores PNM's overall economic picture and has negative consequences for customers. The EUE requires that a utility be made financially neutral. PNM's decoupling proposal is designed to be a financial windfall[18] instead.

Mr. Feingold defines "margin revenues" as "the non-gas cost-of-service for the utility that is approved in the last rate case." Id. at p.86. He uses the term to mean the total non-gas revenue requirement approved in the last rate case. Id. at p.197. His RR 16 "only uses the customers approved in ... the Company's last rate case." Id. at p.88. PNM's decoupling proposal does not take into account revenue contributions of new customers. Id. at p.126. Mr. Feingold agreed that use per customer can decline but PNM can still recover its margin revenue. Id. at p.129. This decline in use per customer triggers an upward adjustment (an increased charge) even when new customers exactly make up for reduced total use by old customers, so that the throughput, or volume of gas PNM sells, is the same. Id. at pp.122-125. In other words, under PNM's decoupling proposal, when PNM sells precisely the same amount of gas because of customer growth and there is no reduction in throughput or revenues,

[18] "I think ... that although the adjustments to any one customer is not large relative to the customer's overall bill, when you add up all of those adjustments for the customers that the company serves, that ... can have a material impact on the ability for the company to recover the revenues approved by the Commission." Tr. 12/14/06, p.80.

according to PNM witness Feingold, the "decline in use per customer when compared to the rate case number generates the need for an upward adjustment [increase] to compensate the company for that loss in revenue." *Id.* at pp.124-125. But there is no loss in revenues, just a decrease in revenue per customer.

Under the decoupling proposal PNM will be "compensated" for lost revenues even when revenues do not go down. They will also be compensated, under Mr. Feingold's decoupling proposal, when use per customer declines, but total revenues are higher than those approved in the previous rate case. Under this scenario, customers will still be assessed a surcharge. *Id.* at p.160.

The only way to receive a credit is if per customer use increases, as can happen during very cold weather. PNM points to the resulting stabilizing effect on bills, which would be lower during cold winters and higher during mild winters, as a benefit to customers. This benefit would, over the last five years, have come with a price. The cost to PNM's customers would have been over $16 million. Moreover, PNM's customers have significantly reduced per customer gas use in recent years, primarily in response to higher natural gas prices. The effectiveness of the price signal and of the customer conservation response would be reduced by decoupling.

PNM will be compensated for "losses" that do not occur, and even when the "losses" per customer are accompanied by an increase in total revenue, PNM will be compensated for these losses, too. And all of this is accomplished with decoupling's simple true-up mechanism. Mr. Feingold describes all of this as necessary: "we have to move towards a new ratemaking paradigm...." *Id.* at p.157. Other regulatory

innovations[19] have been labeled in a similar way. The results, particularly for electric restructuring, have been much higher rather than lower rates: "... Pennsylvania is not the only place where there has been some disappointment." Tr. 12/14/06, p.184. In the field of utility regulation, new paradigms have proven very expensive in the last ten years. Fortunately, the New Mexico Legislature prevented New Mexico from suffering the major electric rate increases experienced by the many states that accepted the arguments that electric deregulation would lower rates. Tr. 12/14/06, pp.184-187, 238

In recent years PNM's total throughput (volumes of gas sold and delivered) has increased due to customer growth even while the use per customer has declined. *Id.* at p.179. If decoupling had been in place during the years 2001-2005, PNM would have received an additional $16.5 million from its natural gas customers, an average of $3.3 million a year. Tr. 12/14/06, p.91. In that time frame, it did not have significant energy efficiency programs in place.

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[19] In its Order approving Formation of a Holding Company issued on June 28, 2001 in Case No. 3137 (pp.2-3) (emphasis supplied), the Commission authorized PNM to form PNM Resources ("PNMR") and recognized New Mexico's good fortune to still be among the states with traditional utility regulation.

"The Restructuring Act originally called for competition in the New Mexico retail electricity market to begin earlier this year on January 1, 2001, for residential, small business customers, and public schools and colleges, with large business starting one year later. NMSA 1978, Section 62-3A-4(A) (1999). The Legislature gave the Commission authority to delay customer choice and other dates in the Restructuring Act by up to one year. The Commission did so in an Order issued in May of 2000. But for that delay, New Mexico residents, schools and small businesses would have been at the mercy of the prevailing wholesale price for electricity for the last six months. They would no longer have been entitled under New Mexico law to electricity at just and reasonable rates."

"Because the Legislature gave the Commission authority to delay competition, New Mexicans will spend several hundred million dollars less just this year for their electricity. As New Mexico State University Professors Dr. Douglass Gegax and Dr. Paul Turner concluded in September of 2000 at a Commission Work Session on Recent Market Conditions Affecting Electricity Restructuring: 'It is interesting to note that the current regulated price path looks pretty good for New Mexico consumers.' California Electricity Markets: Lessons Learned for New Mexico, September 26, 2000, p.26."

PNM's recently established gas energy efficiency program has 934 participants out of about 470,000 natural gas residential gas customers. AG Brief in Chief, p.14. The AG also points out that PNM's gas energy efficiency program investments are funded "by a customer surcharge through a rate rider...." AG Reply Brief, p.6.

Staff witness Sisneros testified in favor of decoupling and about the complexity of determining the exact amount of lost revenues PNM would experience because of company efficiency programs. Staff Exhibit 5 (Sisneros Direct), pp.10-11. At the hearing he agreed that Staff and the parties are capable of dealing with those problems if "given adequate time and resources it's possible." Tr. 12/20/06, p.112.

The AG stressed that at hearing PNM admitted RR 16 as proposed is "flawed in that additional throughput per customer did indeed result in increased margin and thus a significant incentive to increased throughput. (Transcript, Dec. 19, p.114....)" AG Reply Brief, p.9. PNM admitted this flaw and offered to correct it. PNM Brief in Chief, p.102. "...the description would be corrected ... with that clarification, the CNA [decoupling] will eliminate the throughput incentive for PNM ... the CNA provides significant benefits to customers and the Company."

The Commission agrees that the record shows benefits of decoupling for PNM, but does not agree that it would benefit customers. PNM's proposal is inconsistent with and oversteps the EUE. It would not, as required, make PNM "financially neutral" relative to resource choices. It would, instead, give PNM insulation from a large variety of business risks including the risk of customer response to higher prices. PNM properly bears those risks. PNM's presentation on this issue is unpersuasive. PNM fails to meet its burden of proof.

The EUE requires the Commission to "identify any disincentives or barriers that may exist for public utility expenditures on energy efficiency and load management, and, if found, ensure that they are eliminated...." NMSA 1978, Section 62-17-5(F) (2005). The Act does not require approval of PNM's proposal to insulate it from the vast majority of its business risks and provide it with an "enhanced opportunity to recover its Commission-approved revenue requirement." Brief in Chief, p.104 (emphasis supplied). PNM is correct that it has an opportunity; but the legal standard is that it be a fair one, not one enhanced by an ill-advised decoupling mechanism.

The record shows that the two rate classes, small commercial and residential, that would be affected by decoupling provide PNM with almost 94 percent of its margin revenues and are about 98 percent of the total number of PNM customers. Tr. 12/14/06, p.217. A result of approving decoupling would be that at least 93 percent of PNM's total revenues would be assured of recovery. *Id.* at 218. This would put PNM in a position of having a significantly reduced overall business risk. Consistent with that position, Staff and other parties contend that PNM would then be entitled to a lower return on equity.

PNM takes a decidedly different view. PNM witness Hadaway asserts that if decoupling and a higher winter customer charge of $15.00 a month (instead of the present charge of $9.00 and PNM's proposed $11.00 charge) "were not being proposed by PNM, it would be appropriate to increase PNM's requested ROE to account for its more risky position." PNM Exhibit 18 (Hadaway Direct), p.28. He relies on the fact that his "peer group" of comparable gas utilities have decoupling. His testimony is that 5 of 10 do. Tr. 12/18/06, p.96. Which means 5 of 10 do not.

Dr. Hadaway's selection of a peer group[20] of this 50/50 composition may or may not reflect the overall industry average. *Id.* at p.97. In any event, PNM has not met its burden of proof in this case concerning decoupling. PNM, if it had decoupling, would have substantially reduced risk and very little uncertainty regarding its revenues. Under Bluefield, this situation would necessarily result in a lower rate of return than what we have determined is fair in this case. The Commission does not agree with PNM that it is entitled to a higher rate of return than what is authorized in this case.

If any other states are significantly reducing a utility's risk with a decoupling plan having the same features as PNM's proposal without reflecting the corresponding reduction in risk and revenue uncertainty in the authorized rate of return, we are not obligated to follow any such departure from established principles. Any such departure from the *Bluefield* standards raises significant issues.

PNM's proposal for decoupling and its related proposal for an increased rate of return in the absence of decoupling do not comport with the fundamental nature of utility regulation. The primary result that would flow from decoupling would be to insulate PNM's revenues from customer response to the higher prices for natural gas experienced in recent years. PNM's request to be so insulated surpasses the proper limits of utility regulation. As the United States Supreme Court explained in *Market St. Ry. Co. v. Railroad Commission*, 324 U.S. 548, 568 (1945). "Even monopolies must

[20] In future rate cases, care should be taken by PNM, Staff and others to ensure that comparable utilities are as similar to the New Mexico utility as possible. The burden will be on the proponent of a comparable group of utilities to document by a written determination by the relevant state commission of the level of any utility's revenues that are assured of recovery if the proponent asserts that the level of risk for the New Mexico utility in the subject rate case is somehow different compared to one or more members of the comparable group.

sell their services in a market where there is competition for the consumer's dollar and the price of a commodity affects its demand and use."

PNM is authorized a return on equity above a risk free rate. One of its business risks is that customers will use less natural gas, per customer, in response to higher natural gas commodity prices. The record in this case shows that despite this per customer decline, PNM's overall sales have increased[21] because of customer growth.

PNM's decoupling proposal would protect it from a wide range of business risks. And PNM wants this protection without any reduction in its authorized return on equity, despite the clear reduction in risk attendant to PNM's proposal. In declining PNM's proposals, we are mindful that an aspect of symmetry is required in utility regulation. The United States Supreme Court made it clear that a utility is entitled to consistent, symmetrical treatment. "Consequently, a State's decision to arbitrarily switch back and forth between methodologies in a way which required investors to bear the risk of bad investments at some times while denying them the benefit of good investments at others would raise serious constitutional questions." *Duquesne Light Co. v. Barasch*, 488 U.S. 299, 315 (1989). Accepting either of PNM's proposals would raise a serious issue concerning that required symmetry.

Although PNM has offered to "fix" the flaw in RR 16, the shortcomings of RR 16 are not amenable to any fix. It goes beyond what the EUE authorizes or requires and it suffers from other shortcomings as well.

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[21] Since early 2003, the average residential cost-of-service component of a bill is now 2.8 percent lower, but over the same timeframe PNM has added 30,000 new customers, an increase of between 6 and 7 percent. Tr. 12/13/06, pp.79, 85.

The parties identified additional problems with PNM's decoupling proposal. They argue it violates the requirement of NMSA 1978, Section 62-8-7(E) that there be a hearing before there is a change in rates, except in the case of several specific cost factors. PNM argues the EUE creates an exception to this hearing requirement. PNM's position is incorrect. A change in sales volumes is not one of the identified exceptions.

PNM's request is contrary to the well-settled doctrine that "where a statute explicitly enumerates certain exceptions to a general grant of power, courts should be reluctant to imply additional exceptions in the absence of a clear legislative intent to the contrary." U.S. v. NEC Corp., 931 F.2d 1493, 1502 (11th Cir. 1991); Davis v. Davis, 911 F.2d 560, 562 (11th Cir. 1990) (courts "are not free to create by interpretation an exception in a statute which is plain on its face"); Cottonwood Mall Shop. Ctr., Inc. v. Utah Power & Light Co., 440 F.2d 36, 40 (10th Cir. 1971), cert. denied, 404 U.S. 857 (1971) (State public utility statutes "must be given a liberal reading to provisions subjecting the activity to regulation while simultaneously giving a more narrow scope to the exceptions"); see also, State v. Board of County Commissioners, 62 N.M. 137, 140-141, 306 P.2d 259 (1957) (anyone claiming the benefit of an exemption must clearly and unmistakably establish his right to it).

Section 62-8-7(E) provides as follows. "Except as otherwise provided by law, any increase in rates or charges for the utility commodity based upon cost factors other than taxes or cost of fuel, gas or purchased power ... shall be permitted only after notice and hearing...." PNM argued it is not changing cost factors so Section 62-8-7(E) does not apply. The AG responds that PNM wants decoupling to recover its costs, and that to "be just and reasonable, rates must be cost-based." Reply Brief, p.10. We agree

with the AG and note that PNM would increase its delivery (transmission and distribution) rate under RR 16 based on the reduction in the amount of gas a customer uses.

The parties also contend that decoupling would discourage ongoing customer-initiated conservation efforts. In effect, under decoupling customers could no longer reduce what they pay to PNM for transmission and distribution. They would only save on the commodity portion of their bill. PNM's reaction is to dismiss as relatively small the additional costs decoupling would impose on customers who voluntarily reduce their own use of natural gas. A PNM customer who conserves on their own will not have the savings associated with a reduction in throughput and Mr. Feingold considers that amount minimal. Tr. 12/14/06, p.235. Earlier, he expressed his opinion on the present treatment afforded PNM's natural gas customers who conserve. "Quite frankly, the way the rates are designed currently, I believe that customers are overpaid to the extent that they reduce their energy consumption by virtue of the fact that they are saving on fixed costs through the variable portion of the rate where that shouldn't be happening." *Id.* at p.231.

The Commission does not agree that customers who conserve are "overpaid" under the present rate design. The record shows that PNM's customers would have paid an extra $16.5 million between 2001 and 2005 had decoupling, as proposed by PNM, been in place. We consider this evidence sufficient to conclude that decoupling would discourage conservation efforts. PNM's proposal is inconsistent with the EUE.

Additional issues such as whether decoupling is inconsistent with regulatory lag or whether it would constitute retroactive ratemaking may have merit but need not be

decided in this case. The Commission finds that decoupling is not in the public interest and is inconsistent with the Public Utility Act.

The EUE requires the Commission to make certain determinations. They apply not just to PNM's natural gas service, but to all natural gas and electric utilities in New Mexico. We will make the necessary determinations in a separate case, one devoted exclusively to those issues. The other affected electric and natural gas utilities will be able to fully participate in that case. The testimony and argument provided in this case, and the Commission's decisions, serve to inform and guide Utility Division Staff and potential parties to that later case of certain issues to be considered and what approaches have already been considered and rejected.

Finally, we note that PNM in its Brief in Chief (p.6) identifies nine states that have decoupling for natural gas utilities, several of which are using a three-year pilot program. PNM suggests a three-year pilot program for New Mexico as an alternative to its proposal. We do not know the details of the decoupling plans in use in those nine states (or how many of the remaining 40 states have rejected a decoupling proposal), but the record in this case conclusively demonstrates that a pilot program is not needed in New Mexico because PNM's decoupling proposal is fatally flawed.

3. Conservation Adjustment

PNM requests that if decoupling is denied, the Commission grant it an annual increase to test period revenues of $2,855,503. The basis for PNM's request is that it wants the increase in revenue requirement to "reflect the impact of a significant decline in per customer usage during the winter of 2005/2006 .... PNM believes that the reduction in usage was a direct result of higher natural gas prices and PNM's efforts to

ATTACHMENT C

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
PUBLIC UTILITIES COMMISSION

IN RE:

APPLICATION FOR RATE CHANGE
PURSUANT TO R.I.G.L. §§ 39-3-10 AND
39-3-11 OF NARRAGANSETT ELECTRIC
D/B/A NATIONAL GRID

DOCKET NO. 3943

DECISION AND ORDER

DATED: January 29, 2009

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
PUBLIC UTILITIES COMMISSION

IN RE:

NATIONAL GRID GAS APPLICATION TO IMPLEMENT NEW RATES — DOCKET NO. 3943

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STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
PUBLIC UTILITIES COMMISSION

IN RE:

APPLICATION FOR RATE CHANGE PURSUANT TO R.I.G.L. §§ 39-3-10 AND 39-3-11 OF NARRAGANSETT ELECTRIC D/B/A NATIONAL GRID

DOCKET NO. 3943

DECISION AND ORDER

I. INTRODUCTION

On April 1, 2008, The Narragansett Electric Company d/b/a/ National Grid (the "Company") filed an application to increase the Company's base distribution revenues for the first time in almost ten years. The Company proposed an increase of $20.04 million, or 4.6% of total gas revenues, representing an additional $72 per year for a typical residential heating customer using 922 therms of energy. The primary factors cited by the Company in support of its rate increase application were increased operation and maintenance expenses, and the need to compensate for historic underinvestment by prior management in the distribution infrastructure. The Company also cited a need to address a loss of revenue due to increasing customer conservation over the years. The Company calculated that it had experienced annualized lost revenues totaling $7.64 million since June 2004 for the residential heating class alone.

The Company's rate application included a request that the Commission consider an important policy issue of first impression in Rhode Island: whether the Company's allowed distribution revenues should be decoupled from the volume of natural gas consumption by its customers. Under traditional ratemaking in Rhode Island and most of the United States,

distribution revenues are based on a volumetric charge established by the regulatory agency. To obtain an increase in the volumetric charge, and a resulting increase in revenues, the utility must in general file a base rate case and demonstrate to the satisfaction of the regulators that the utility's costs and expenses justify an increase. Fifteen states have allowed utilities to modify the volumetric distribution charge approved in a base rate case up or down as needed for the utility to collect an approved amount of distribution revenues, without further review by the regulatory agency. The parties and the Commission devoted considerable time and attention to understanding the advantages and disadvantages to ratepayers of the Company's decoupling proposal.

A. Conduct of the Proceeding.

The record in this case is unusually extensive and complex, addressing as it does numerous contested technical and financial issues as well as broad disputes over important issues of public and ratemaking policy. The Company's initial filing alone totaled over 1,000 pages of testimony and supporting documentation. In response to the Company's base rate application, the Commission received and considered voluminous and detailed pre-filed testimony and exhibits from experts employed by the Division of Public Utilities and Carriers ("Division"). Several intervenors requested and were granted permission to participate in the proceeding, including the Rhode Island Attorney General, the Rhode Island Office of Energy Resources, the George Wiley Center, Conservation Law Foundation, Environment Northeast, the Energy Council of Rhode Island, and Rhode Island Hospital. The intervenors submitted additional written testimony and exhibits. The Commission's review and consideration of these

voluminous materials was further complicated by the restrictive limits on communications with Commission staff recently imposed by the Rhode Island Supreme Court.[1]

After the initial filing, the parties engaged in extensive discovery proceedings. The Commission, Division and other parties propounded over 500 data requests to the Company for information relating to the Company's and its affiliates' management, operations and finances. The Company provided hundreds of pages of written answers and supplemental documentary material in response. The Company also responded to numerous record requests made during the course of the public hearings on this docket.

The Commission conducted twelve days of evidentiary hearings on the Company's proposal in September and October, 2008. Over 160 exhibits, totaling thousands of pages of information, were received into evidence. The Company, Division and other parties presented seventeen witnesses:

For the Company:

1. Nickolas Stavropoulos, Executive Vice President of Gas Distribution-US for National Grid, with responsibility for the Company's regulated gas distribution operations in Rhode Island, Massachusetts, New Hampshire and New York, testified for the Company regarding its overall business operating plan and decoupling proposal;

2. Michael Laflamme, Director of Revenue Requirements for National Grid USA Service Company, Inc., testified for the Company regarding its single year revenue requirement analysis, including sharing of net synergy savings from both the National Grid/Southern Union and National Grid/KeySpan transactions;

3. Susan Fleck, Vice President of Engineering Standards and Policy for National Grid USA, testified for the Company regarding its accelerated pipeline replacement program;

4. Peter Czekanski, Manager of Pricing for National Grid Rhode Island – Gas, testified for the Company regarding adjustments to test year billing determinants and revenues that produce rate year billing determinants, and the Company's proposed tariff changes;

[1] *See Arnold v. Lebel,* 941 A.2d 813 (R.I. 2007).

5. Sean Mongan, Director of Operations and Process Support for the Energy Solutions Service Group for National Grid USA, testified for the Company regarding its proposed Gas Marketing Program;

6. Paul Moul, Managing Consultant, P. Moul & Associates, testified for the Company regarding an appropriate rate of return;

7. Robert Hevert, President, Concentric Energy Advisors, testified on behalf of the Company regarding the effect of decoupling on an appropriate rate of return;

8. James Simpson, Vice President, Concentric Energy Advisors, testified for the Company regarding the mechanics of the Company's decoupling proposal;

9. David Heintz, Assistant Vice President, Concentric Energy Advisors, testified for the Company to explain the Company's proposed rate design for the gas business in Rhode Island;

For the Division:

10. David Effron, a consultant specializing in utility regulation, testified on behalf of the Division of Public Utilities and Carriers regarding the Company's proposed revenue requirement, the proposed pension reconciliation mechanism, and the accelerated pipeline replacement expense reconciliation mechanism;

11. James Rothschild, a financial consultant specializing in utility regulation, testified on behalf of the Division of Public Utilities and Carriers regarding the Company's proposed cost of capital with and without decoupling;

12. Don Ledversis, Gas Inspector for the State of Rhode Island, testified on behalf of the Division of Public Utilities and Carriers regarding the condition of the Company's distribution infrastructure;

13. Bruce Oliver, President, Revilo Hill Associates, testified on behalf of the Division of Public Utilities and Carriers regarding the Company's proposed revenue requirement, decoupling, non-firm distribution rates, and other rate design issues;

For the Intervenors:

14. John Farley, Executive Director, The Energy Council of Rhode Island, testified on behalf of TEC-RI regarding the Company's decoupling, low income discount and non-firm distribution rate proposals;

15. James DeMetro testified on behalf of Rhode Island Hospital regarding the Company's proposed non-firm distribution rates;

16. Seth Kaplan, Vice President for Climate Advocacy and the Director of the Clean Energy/Climate Change Program, Conservation Law Foundation, testified on

behalf of the Conservation Law Foundation regarding the Company's decoupling proposal;

17. James Grasso, President, Silent Sherpa Energy Consulting and Professional Services, Inc., testified on behalf of Silent Sherpa regarding the Company's non-firm distribution rates.

All parties, Commissioners, Commission counsel, and Commission staff were given broad latitude to examine the witnesses regarding their pre-filed direct and rebuttal testimony, and to introduce supplemental testimony and other evidence during the hearings. At the direction of the Chairman, the hearings were conducted so as to ensure a full and compete record for the Commission to consider in deciding the case.

The Commission also received and carefully considered numerous public comments. The Commission heard public comment on the Company's proposals from 30 individuals at open meetings held in Pawtucket, Woonsocket, Middletown and Warwick in June 2008: Sally McAuley, Raymond Matthew, Ernie Marot, Michael Dyer Ryan, Julie Silvia, Darlene Magaw, Joseph Pamula, Cindy Chompka, Jackie Archambault, Jim Healy, Charles A. High, Henry Shelton, John A. MacLennan, Don Mallinson, Frank Bozyan, Irene Santos, Manuel Marques, Elizabeth Dees, Bill O'Connell, Harry Bogosian, Virginia Gonsalves, Sister Carol Weaver, Stephanie Cannady, Lela Coons, Marie C. Hennedy, John Colby, Elizabeth Marsis, Maggie Rogers, Erik Dufresne and Roberta Fitton. The Commission heard additional public comment from 21 individuals during the evidentiary hearings: Julie Gill, Christopher Powell, Peter Cassels, Jan Campbell, Michael Januario, Karina Lutz, Sandra Morra, Elaine Gambardella, Stephen Kapalka, Jessica Jennings, Thomas J. Murphy, Michael Seymour, Kenneth Clark, Nancy Clark, Elizabeth Clark, Donald DeSantis, Kathie Foorsheim, Sally Lapides, David Pallante, Judith Croyle and Charles Pinning. Customers who commented were opposed to a rate increase and concerned about the effects on their households, particularly elderly and at-risk

households. Customers were also concerned about the collateral effects of rate increases on businesses, churches, schools and non-profit organizations. Several customers commented that the Company should be more aggressively trying to reduce its costs, rather than increasing rates. Other customers complained about the Company's failure to communicate adequately with customers about Company initiatives, particularly efforts by the Company to relocate gas meters to the front of customers' homes, and about deficiencies in the Company's Value Plus Installer conversion program.

After the conclusion of the hearings, the parties and intervenors submitted post-hearing briefs summarizing the arguments and evidence presented, and addressing certain legal issues presented by the Company's proposals. The Commission also received reply briefs from the parties and intervenors commenting on each others' post-hearing submissions.

B. Applicable Legal Standards

As noted above, many public commentors expressed the view that energy costs have increased significantly in recent years and that no rate increases should be allowed. The Commission takes seriously its responsibility to thoroughly review proposed rate increases, and has devoted substantial time and resources to investigating the justification for the Company's proposed expenses, ultimately reducing the Company's revenue request by a substantial amount. At the same time, the Commission must allow the Company sufficient resources to deliver safe and reliable natural gas service to approximately 250,000 customers who rely on gas in their homes and business in virtually all cities and towns statewide. The Company, like its customers, faces rising costs for the goods and services it needs to deliver natural gas. The Company's interim filings relating to increases or decreases in the commodity cost – the cost of natural gas itself – do not address these distribution costs.

The Rhode Island General Assembly has declared that it is the policy of the state

> To provide fair regulation of public utilities and carriers in the interest of the public, to promote availability of adequate, efficient and economical energy, communication and transportation services and water supplies to the inhabitants of the state, to provide just and reasonable rates and charges for such services and supplies, without unjust discrimination, undue preferences or advantages, or unfair or destructive competitive practices . . . . .

R.I.G.L. § 39-1-1; *see also* R.I.G.L. § 39-2-1 (utility rates and charges must be "reasonable and just"); R.I.G.L. § 39-2-2 (prohibiting rate discrimination). The Commission's review of the Company's proposals must be conducted taking this policy into account. The Company bears the burden of proof to show that its rate increase is necessary in order to obtain just and reasonable compensation for the service rendered. R.I.G.L. § 39-3-12. There is no single formula for measuring just and reasonable rates; the Commission has discretion to select a measurement approach that is supported by the record. *Providence Gas Co. v. Burman*, 119 R.I. 78, 376 A.2d 687 (1977).

C. Summary of Decision.

The Commission rendered its decisions on the issues presented by the parties at an open meeting on November 24, 2008. As reflected in the Company's compliance filing, the Commission's decisions in this docket result in the Company's revenue deficiency being reduced from the $20,036,103 initially proposed to $13,659,773. Thus, the Company's allowed distribution revenue will increase by 10.88% from $125,606,713 to $139,266,486. For a typical residential heating customer using 922 therms of natural gas, the approved new base rates represent an increase of $56 per year. Combined with other scheduled changes under the Gas Cost Recovery and Distribution Adjustment Clause, however, this will result in a net 4.1% rate reduction, which translates to an annual reduction of about $64 per year. The Commission denied the Company's proposed return on equity of 11.5%, finding that a lesser return of 10.5% is just and reasonable. Other regulatory adjustments include: reducing the Company's proposed

health care expense by $907,456; reducing the Company's proposed FAS 112 expense (relating to post-employment benefits other than pension) by $170,000; reducing the Company's proposed synergy savings from the Southern Union merger by $1,054,609; eliminating the Company's proposed $1,377,000 gas marketing program; and reducing the Company's proposed low income uncollectible accounts receivable adjustment by $150,000.

The Commission also (1) approved a 10% distribution rate discount for qualifying low income customers, (2) approved the Company's accelerated pipeline replacement program to address the increasing number of gas leaks in Rhode Island's aging distribution infrastructure, (3) approved the Company's proposed reconciling mechanism for pension and post-retirement benefits other than pension expense, and (4) approved distribution rates for non-firm transportation customers that will be set at a fixed percentage of 80% of the otherwise applicable firm transportation rate. The Commission rejected the Company's proposed revenue decoupling mechanism and a proposed reconciling mechanism for gas-supply related bad debt.

In granting the Company a distribution revenue increase of $13,659,773, the Commission is allowing additional funds for the Company to modernize its infrastructure and provide safe, efficient and reliable service to customers. The Commission's adjustments to the Company's proposed expenses and the revised 10.5% return the Company will be allowed to earn on its investment reflect the difficult economic conditions in the state that are faced by both the Company and its customers. The 10.88% revenue increase granted by the Commission is significantly lower than the approximately 16% increase requested by the Company; however, the Commission believes that the rates it has allowed are just and reasonable and will permit the Company to earn a fair rate of return. The Commission believes that it has properly balanced the

competing interests presented by the parties, consistent with the Commission's statutory duty under Rhode Island law.

II. SUMMARY OF THE COMPANY'S RATE FILING.

The Company's initial filing requested a base revenue increase of $20,036,103 million, to $149,885,295. Ex. NGrid 3 at 6 (Laflamme Direct). The Company developed its revenue request based on a test year ending September 30, 2007. The Company made adjustments to test year revenues and expenses to reflect "known and measurable" changes relating to any one-time, out of period or unusual activities. Ex. NGrid 3 at 7 (Laflamme). *See Narragansett Electric Co. v. Harsch*, 117 R.I. 395, 368 A.2d 1194 (1977) (Commission may accept known and measurable changes that affect test year data with certainty). The Company then made a number of pro forma changes to reflect anticipated cost and revenue changes through the end of the rate year, September 30, 2009. These include changes in labor and benefit costs, postal rate increases, adjustments for the pending sale of the Company's Providence, R.I. office, rate case expenses and inflation. The operating results were also adjusted to include operations & maintenance expense and capital costs associated with the Company's proposed Gas Marketing Program and accelerated infrastructure replacement program. Ex. NGrid 3 at 8 (Laflamme).

To calculate the $149 million of base revenues proposed in its initial filing, the Company (1) excluded actual Gas Cost Recovery revenues recorded in the Test Year, (2) adjusted interruptible firm revenues to the base rate credit level of $1.6 million, (3) eliminated actual energy efficiency surcharges recorded in the test year, (4) eliminated actual gross receipts tax collections and gross receipts tax expense recorded during the test year, (5) adjusted operating revenue related to out of period, non-recurring, unbilled and weather normalization revenues recorded in the test year, (6) adjusted for the Company's service contract program

costs, and Allowance for Funds Used During Construction and interest on customer arrears, and (7) adjusted all components of the test year base rate revenues to reflect normal weather. The Company also made pro forma adjustments to reflect total base rate revenues expected in the rate year, including adjustments to the base rate recovery component for the Low Income Heating Assistance Plan, Low Income Weatherization Program, Advanced Gas Technologies Program, and Environmental Remediation cost recovery. Ex. NGrid-3 at 9-10 (Laflamme).

To calculate the $123 million of operating expenses proposed in its initial filing, the Company (1) eliminated from the cost of service total gas expenses of $300,428,013 recorded in the test year, (2) excluded non-gas O&M expenses recovered through the GCR, (3) eliminated gas-related uncollectible expenses at the test year uncollectible rate of 2.10%, (4) corrected an accounting error associated with Environmental Remediation cost amortization, (5) excluded energy efficiency expenses and gross receipts tax expense recorded in the test year, (6) adjusted test year Y2K and legacy system amortization expense, (7) excluded an expense credit erroneously recorded in the test year, (8) included an expense credit for overhead associated with test year service contract labor, (9) eliminated certain computer hardware lease expense, (10) adjusted the Company's accrued vacation liability, (11) adjusted for a medical expense billing lag, (12) reclassified donations to other O&M categories, (13) excluded all costs to achieve merger synergies from the Southern Union and KeySpan transactions, and (14) excluded the approved merger synergy allowance from the Southern Union transaction. The Company also made pro forma expense adjustments to test year salary and wages, medical and dental expenses, group insurance expenses, pension and other post-retirement benefit expenses, employee thrift plan expenses, postage expenses, rate case expenses, office expenses, automated meter reading

expenses, LNG-related expenses, and made an inflation adjustment. Ex. NGrid-3 at 11-24 (Laflamme).

The Company made additional adjustments to depreciation expense ($911,576), municipal tax expense ($213,448), and payroll tax expense ($188,066). The Company's depreciation study resulted in a composite depreciation rate of 3.36%. Excluding the Company's investment in the Providence, Rhode Island office, the composite depreciation rate is 3.38%. This composite rate was applied to rate year depreciable plant to arrive at rate year depreciation expense. For municipal tax expense, the Company calculated a three year average percentage increase of 1.38%, and applied this rate of increase to the Company's most recent 2007 municipal tax assessment, adjusted to exclude the Providence, Rhode Island office property. Payroll tax expense was adjusted by applying the net change in rate year versus test year O&M salaries and wages to test year payroll tax expense. Ex. NGrid-3 at 40-42 (Laflamme).

The Company proposed a rate base of $285,241,458. Ex. NGrid-3 at 44 and Attachment NG-MDL-1 at 24. To calculate rate base, the Company used a five quarter average of net plant in service plus cash working capital, materials and supplies, prepayments and deferred debits, less deferred income taxes, customer deposits and an injuries and damages reserve. The Company included a hold harmless base rate credit of $30,337,343 relating to the tax asset basis step up realized by the Company upon its acquisition of the regulated Rhode Island gas assets of New England Gas Company. Both plant in service and accumulated depreciation amounts were adjusted for the anticipated sale of the Company's Providence, Rhode Island office. The Company's proposal was based on forecasted additions to plant in service of $36,679,000 in the twelve months ending September 30, 2008, and $60,780,000 in the twelve months ending September 30, 2009. Ex. NGrid-3 at 42-44 and Attachment MDL 1, p. 26 of 33.

The Company proposed an overall cost of capital of 9.27%, including a return on equity of 11.5%. Ex. NGrid-3 at 45.

The Company also requested a number of significant modifications to its tariff. These included: (1) introducing a revenue decoupling mechanism to reconcile actual annual revenue per customer with the revenue per customer approved in this rate case; (2) introducing new annual reconciling mechanisms for certain expenses previously fixed in base rates, including pension and other post-retirement benefit expense and commodity-related bad-debt expense; (3) introducing a discounted billing rate for low income customers, and (4) capping value of service pricing for interruptible service customers at 150% of the comparable firm tariff rate.

III. DECISION

A. Revenue Requirement Issues.

The Company's proposed revenue deficiency is based in part on three contested items: (1) the percentage of common equity to be included in the Company's capital structure for ratemaking purposes, (2) the appropriate cost of common equity, and (3) the allowable rate base through the end of the rate year. These items are addressed in turn below.

1. Capital Structure

The Company and the Division agree that, although the Company's Rhode Island natural gas operations are a division of The Narragansett Electric Company ("Narragansett Electric"), Narragansett Electric's actual capital structure contains a large proportion of common equity and is inappropriate for use in the ratemaking process. Ex. NGrid-9 at 10-11.[2] The

[2] Narragansett Electric is a subsidiary of National Grid USA. National Grid USA is a subsidiary of National Grid plc. The capital structure of National Grid USA and Subsidiaries as of September 30, 2007 was about 60% equity and 40% debt. The capital structure of Narragansett Electric was about 90% equity and 10% debt. Ex. NGrid-9 at 11-12 (Moul Rebuttal); Data Response COMM 3-4.

Company and the Division disagree, however, on the appropriate alternative measure. The Company proposed a capital structure of 47.71% equity, 40.63% long-term debt, and 11.66% short-term debt, calculated based on the equity ratios of a proxy group of other U.S. natural gas utilities. Ex. NGrid-8 at 4 (Moul). The Division proposed using the capital structure of the Company's parent, National Grid plc: 37.77% equity, 59.06% long-term debt, and 3.17% short term debt. Division Post-Hearing Mem. at 5; Ex. DIV-5, JAR Schedule 1 (Rothschild).

Company Position. The Company argued that its parent company's capital structure should not be used for ratemaking for several reasons. First, it would mean using the capital structure of a non-domestic, unregulated holding company that owns and operates a global operation encompassing a wide range of unregulated activities. The unregulated activities have different business risks. Ex. NGrid-9 at 9-16; Tr. 9/10/08 at 9-10. The Division's expert should have, but did not, take into account the nature of National Grid plc's unregulated activities or the reasonable range of capital structures in the United Kingdom. Tr. 9/11/08 at 74-75.

Second, the record is clear that the capital structure recommended by the Division is not typical of a capital structure for a regulated gas company operating in the U.S. *See, e.g.,* Ex. DIV-31. In that regard, the record shows that the average capital structure associated with the proxy group that the Division's witness uses for the ROE calculation has an average common equity ratio of 49.12% and the median is 47.05%. Ex. DIV-5 at Schedule JAR-7; Ex. NGrid-9 at 14; Tr. 9/10/08 at 12-13. In addition, the Division's own data shows that no regulated gas or electric utility obtaining a Commission decision on a rate case year-to-date in 2008 had a capital structure with less than 41% common equity and no regulated gas company had a common equity ratio less than 46% common equity. Ex. DIV-31 at 4-5. The average common equity

ratio was demonstrated to be 52.06%. *Id.* As a result, these factors underscore the unreasonableness of the Division's recommendation and argue for adoption of the Company's proposed capital structure.

Third, the record shows that there is a different regulatory structure in the UK and that the regulator of National Grid's UK business does not utilize the capital structure represented by its U.S. Generally Accepted Accounting Principles ("GAAP") accounts when setting rates. *Id.* at 17-18; Tr. 9/10/08 at 10-11, 50-52. Instead, rates are set in the UK based on a Regulatory Asset Value ("RAV"). The RAV has no direct relationship to the book value of the UK businesses and was derived from a combination of replacement cost and market value that is increased by inflation every year. Thus, even if it were appropriate to impute the capital structure for National Grid plc to the Rhode Island operations, which it is not, the equity component determined in accordance with the US GAAP must be adjusted to recognize the difference between the RAV and the US GAAP book value of the UK regulated businesses. This procedure is necessary to ensure that National Grid's consolidated capital structure as applied to the Company reflects the regulatory value of assets in both the US and the UK. The adjustment would increase National Grid's consolidated common equity ratio determined in accordance with US GAAP by approximately eight percentage points. Ex. NGrid-9 at 17-18.

Fourth, the record shows that, even if it were appropriate to look to National Grid plc for the capital structure, the Division's witness has not correctly stated the equity ratio for National Grid plc in accordance with U.S. GAAP. *Id.* at 15. Specifically, in calculating the parent company's capital structure, the Division's witness failed to take into account approximately $3.7 billion of cash, cash equivalents and marketable securities carried on its fiscal 2007 balance sheet. *Id.* These cash balances should have been subtracted from

outstanding debt balances to compute the capital structure ratios, but were not. *Id.* at 15-16. If this correction were made, the common equity ratio for National Grid plc would total 44.36%, and adjusted for the RAV of National Grid plc/s regulated UK businesses, the actual common equity ratio that would apply to the Rhode Island operations would be 52.19%, rather than the 37.77% incorrectly calculated by the Division's witnesses. *Id.* at 16-18.

Significantly, the Division's witness testified that he was "not aware" of the differences in the UK regulatory system before he made his recommendation on capital structure. Tr. 9/10/08 at 193. The witness further testified that he only became aware of the RAV method of dealing with rate base after receiving a response to a data request on the Company's rebuttal testimony. *Id.* at 194. The witness testified that he felt he was on "comfortable ground" with the "end result" without knowing anything about the RAV. *Id.* at 194-195. However, given the differences that do exist and are proven on the record for this proceeding, it is clear that an accurate calculation cannot be performed without knowledge of the RAV implications. Therefore, this omission has the effect of undermining the "end result" recommended by the Division's witnesses.

Division Position. In rebuttal, the Division argued that using the capital structure of National Grid plc is reasonable because (1) the debt rating of the Company's Rhode Island operations is dependent on the financial condition of the holding company, (2) the subsidiary's common equity was not raised from common equity holders, but through debt sources from the parent, (3) the holding company's A minus bond rating indicates that its capital structure is appropriate, (4) using the Company's 47% common equity ratio does not carry any value to ratepayers given that Rhode Island operations would still be financed by the UK holding company that maintains a lower equity percentage, and (5) if the Company's ratio is used, "not

only would Rhode Island ratepayers fund much more costly equity that, in reality, is never actually utilized for the Rhode Island operations, the hypothetical equity would then have to be grossed up for federal income taxes for an overall cost rate of almost 17.7%." Division Post-Hearing Mem. at 5-9; Tr. 9/11/08 at 76-77, 120-123 (Rothschild); Ex. DIV-6 at 6-7 (Rothschild Rebuttal).

Commission Decision. The Commission will use a utility's actual capital structure in setting rates, unless that capital structure is not reasonable for rate-setting purposes. If the actual capital structure is not reasonable for rate-setting purposes, the Commission may impute a capital structure consistent with market's expectations for a regulated utility. *Blackstone Valley Electric*, Order No. 13877 (1992) (using actual capital structure); *The Narragansett Electric Company*, Order No. 14857 (1995) (settlement using actual capital structure); *The Narragansett Electric Company*, Order No. 16200 (2000) (settlement using imputed capital structure); *In re New England Gas Company*, Docket No. 3401 (2002) (settlement using imputed capital structure of 43.6% common equity). The Commission finds that the Division's reliance on the actual capital structure of National Grid plc is not appropriate because the Division's expert did not make adjustments that should have been made to recognize the different treatment of regulatory assets in the U.K., or the approximately $3.7 billion of cash and equivalents on National Grid plc's balance sheet. Ex. NGrid-9 at 15, 17-18. The evidence indicated that the Division's expert was unfamiliar with U.K. accounting conventions cited by the Company until after he submitted his direct testimony. Tr. 9/10/08 at 193-195. The Company's proposed capital structure is more typical of a capital structure for a U.S. regulated gas company. Ex. DIV-5, Schedule JAR-7; Ex. NGrid-9 at 14; Tr. 9/10/08 at 12-13. For all of these reasons, the Commission approves the Company's proposed capital structure of 47.71%

equity, 40.63% long-term debt and 11.66% short-term debt based on the proxy group of other U.S. natural gas utilities.[3]

2. Return on Equity.

The Company proposed a weighted average cost of capital of 9.19% and an allowed return on equity of 11.50%. Ex. NGrid-8 at 2 (Moul). The Division proposed a weighted average cost of capital of 8.56%[4] and an allowed return on equity of 9.95%, assuming the Division's proposed capital structure. Ex. DIV-5 at 4 (Rothschild).[5] The Company proposed, and the Division did not question, continuing the existing earnings sharing mechanism for earnings above the allowed rate of return. Earnings up to 100 basis points above the allowed return on equity established in this proceeding will be shared 50/50 between ratepayers and the Company. Earnings of more than 100 basis points above the allowed return will be shared 75/25 between ratepayers and the Company. Ex. NGrid-15, Attachment NG-PCC-5 at 231; NGrid Response to Commission Record Request No. 24.

Company Position. The Company arrived at its proposed return on equity by measuring the cost of equity of a proxy group of seven natural gas companies using four methods: discounted cash flow ("DCF"), risk premium analysis ("RP"), capital asset pricing model ("CAPM"), and comparable earnings approach ("CE"). Ex. NGrid-8 at 5 (Moul).

The DCF model measures the value of an asset as the present value of future expected cash flows discounted at the appropriate risk-adjusted rate of return. At its simplest, the DCF return on common stocks consists of a current dividend yield and future price

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[3] Commissioner Bray dissents from this portion of the Decision and would adopt the Division's position for reasons stated on the record at the November 24, 2008 Open Meeting. Tr. 11/24/08 at 107.

[4] Based on projected cost of short-term debt of 2.58% vs. the Company's projected short-term debt cost of 4.59%. Tr. at 8/27/08 at 156.

[5] The Division proposed a cost of equity of 9.50% if its recommended capital structure were not used. Division Post-Hearing Reply at 2; Ex. DIV-5 at 4 and Schedules JAR 2 and 7.

appreciation of the investment. The DCF methodology requires the use of an expected dividend yield to establish an investor-required cost of equity. The adjusted dividend yield for the Company's proxy group was 3.86%. The Company's expert calculated a growth rate of 5.25%, a 0.54% upward leverage adjustment, and a 0.19% upward adjustment for flotation costs. Ex. NGrid-8 at 22-38 (Moul).

Under the risk premium approach, the cost of equity is determined by corporate bond yields plus a premium to account for the higher risk of equity compared to debt. The Company's expert concluded that a 6% yield on A-rated public utility bonds represents a reasonable yield expectation, and that 5.25% is a reasonable common equity risk premium. Ex. NGrid-8 at 38-43 (Moul).

The CAPM methodology uses the yield on a risk-free interest bearing obligation plus a rate of return that is proportional to the systematic risk of an investment. To compute the cost of equity using the CAPM method, three components are needed: a risk free rate of return, the beta measure of systematic risk, and the market risk premium derived from the total return on the market of equities reduced by the risk-free rate of return. The CAPM also takes into account the size of the company or portfolio for which the calculation is performed. The Company's expert calculated a 4.75% risk free rate of return, a leverage adjusted beta of 1.02, a market premium of 7.39% and a size adjustment of .97% to arrive at a CAPM return of 13.45%. Ex. NGrid-8 at 44-49 (Moul).

The Comparable Earnings approach looks at the returns realized by unregulated companies with risks that are comparable to regulated public utilities. One method involves selecting another industry or industries with comparable risks to a public utility, and then using the results for all companies in that industry as a benchmark. A second method involves

selecting parameters that represent similar risk traits for the public utility and unregulated comparables. The Company's expert selected comparable unregulated companies with six categories of comparability designed to reflect the risk of natural gas utilities. Under the Company's CE approach, the cost of equity was 13.90%. *Id.* Ex. NGrid-8 at 49-53 (Moul).

The average return of the Company's DCF, RP and CAPM models was 11.58%, which the Company adjusted to arrive at its proposed return of 11.50%. NGrid Post-Hearing Mem. at 12; Ex. NGrid-8 (Moul Pre-Filed Direct Testimony) at 7.

The Division's proposed rate of return is inordinately low for several reasons. First, the Division expert's DCF model uses the "retention growth rate" method, which requires an assumption of the return on book common equity for a proxy group. Ex. NGrid-9 at 22-23; Tr. 9/12/08 at 22-24. The Division's expert selected 12% for his key input value, which was the second lowest value in his data set of 10 values. *Id.* This approach introduced a "significant downward bias" causing the DCF results to be biased and unreasonably low. *Id.* To be valid, the Division's expert should have selected a balanced approach using a measure of central tendency, such as an average of the values, the median or a midpoint. Tr. 9/12/08 at 22-24. A balanced approach would have resulted in a higher value comparable to the Company's calculation (such as 10.25%, 10.03% and 10.68% depending on the choice of central tendency measure). *Id.*

Second, the Division's rate of return on common equity is significantly lower than almost any other utility for which a rate of return has been set in the most recent reported rate cases, according to information submitted by both the Company and the Division. *Id.* at 5; Ex. DIV-31. According to the Company's data, the average rate of return on common equity for natural gas utilities was 10.27% in the period October 1, 2006 through August 31, 2007. Ex.

NGrid-9 at 5 (Public Utility News, dated December 28, 2007). According to the Division's data, the average rate of return on common equity for natural gas utilities was 10.24% in calendar year 2007 and 10.35% for the first two quarters of 2008. Ex. DIV-31 (Regulatory Research Associates, dated July 2, 2008).

Third, the Division's rate of return fails to take adequate account of volatility in the capital markets and turmoil in the credit markets. The record shows that the cost of common equity has increased as a result of the global financial crisis because of a large increase in the risk premium which is currently estimated to be a 50 to 100 basis point increase in the cost of equity capital. Ex. NGrid-9 at 6-8; Tr. 10/22/08 at 21-22, 66-67. The Company is facing a significant new challenge in terms of assuring investors that their capital is safe with the Company. Ex. DIV-69. There can be no dispute that the Company will be faced with market realities in financing its operations following the Commission's rate case decision, and therefore, these realities need to be considered in the final result.

Lastly, the Division's expert failed to provide any record support for his 45 basis point adjustment to the cost of common equity to account for the higher financial risk associated with this proposal to set rates based on National Grid plc's lower common equity ratio. The Company demonstrated that rather than making an arbitrary adjustment, there are objective methods widely accepted in the financial literature that can be used to quantify the impact of a lower equity ratio on the cost of common equity. Ex. NGrid-9 at 37. By applying these methods, the Company demonstrated that, if the Commission sets rates based on National Grid plc's equity ratio of 37.77%, rather than the Company's proposed 47.71% ratio, the return on equity decided in this proceeding should be adjusted upwards by 98 basis points not 45 basis points. *Id.* at 3.

Division Position. The Division based its recommendation on the DCF method, applied to a comparative group of natural gas utilities. Ex. DIV-5 at 10 and Schedule JAR 3 (Rothschild). The Division's expert also presented a CAPM analysis to support his conclusion. Ex. DIV-5 at 24 (Rothschild). The Division disputed the Company expert's DCF methodology because it added a 0.54% upward leverage adjustment, and a 0.19% upward adjustment for flotation costs. The Division presented testimony that these adjustments are contrary to basic finance principles, and incorporate earnings per share growth rates that are not reflective of long term sustainable growth required for the constant growth form of the DCF analysis. Ex. DIV-5 at 57 (Rothschild). The Division also argued that the Company's risk premium analysis is inconsistent with Commission precedent, Ex. DIV-5 at 58-63 (Rothschild), and that the Company's CAPM analysis is flawed. Among the errors in the Company's CAPM analysis, (1) it improperly uses the arithmetic average, (2) it uses short term analyst forecasts as a proxy for long term sustainable growth, (3) it uses Value Line's five-year projection of total returns on the stock market as if it were intended to be a reflection of investor expectations when, in fact, Value Line has no such intention, and (4) it improperly inflates the beta as applied to the risk premium. Ex. DIV-5 at 64 (Rothschild).

Commission Decision. The Commission has historically expressed a preference for the use of the DCF methodology to determine return on equity. *See, e.g., In re Valley Gas Co. & Bristol & Warren Gas Co.*, Docket No. 2276, Order No. 14834, at 12 (1995) ("this Commission has consistently stated its preference for the use of the discounted cash flow (DCF) methodology"). Using the DCF methodology and a proxy group of companies, the Division's expert arrived at a 9.95% return. However, the record reflects that minor adjustments to the Division's DCF methodology would have produced a higher return. For example, the Division's

DCF expert used 12% as a key input value, which was the second lowest value in his data set of ten values for his proxy group. If he had used the average value of this data set his DCF result would have moved to 10.25%. Ex. NGrid -9 at 22-23; Tr. 9/12/08 at 22-24.

The Company arrived at its proposed 11.5% return on equity by averaging the results of three out of four return on equity calculations, and making upward adjustments to some of its calculations that were challenged by the Division. Ex. NGrid-8 (Moul Pre-Filed Direct Testimony) at 7-8. While the Company's expert proffered explanations for his blended approach, the Division presented evidence that alternate assumptions and calculations would significantly lower the Company expert's result. For example, the Division presented credible evidence that the Company's CAPM analysis, which produced a return on equity of 13.45%, contained a number of flaws. Ex. DIV-5 at 44-45 (Rothschild). The Division also presented testimony that the Company's use of a leverage adjustment and a flotation cost adjustment in its DCF calculation were inappropriate. Ex. DIV-5 at 57 (Rothschild). Excluding these adjustments would have reduced the Company's return on equity based on the DCF method to 9.11% from 9.84%, and reduced the Company's proposed blended rate of return accordingly. Ex. NGrid-8 (Moul Pre-filed Direct Testimony) at 7-8.

The Commission therefore finds that while the expert analyses presented by the Division and the Company are useful indicators of a reasonable range for a return on equity, neither is definitive. In arriving at this conclusion, the Commission notes that the Division's proposed return on equity is below – and the Company's above – recent average rates of return on common equity for other U.S. natural gas utilities. Evidence submitted by the Company, and not disputed by the Division, shows that the U.S. average return on equity for gas utilities is 10.27%. Approximately two thirds of U.S. gas utilities have been allowed returns on equity

between 10 and 10.9%. Tr. 8/27/08 at 23-24; Ex. NGrid 9 at 5 (Moul). Some of the other natural gas utilities with allowed returns in this range have decoupling mechanisms in place. Ex. NGrid-18 at 11 (Hevert); Tr. 9/10/08 116-123. The record reflects that while many utility commissions have not made explicit reductions to authorized return on equity on account of decoupling, there is evidence that in some proceedings the regulatory agency has found it appropriate to reduce the return on equity of a utility that has revenue decoupling. Ex. NGrid-18 at 26 (Hevert).

The Division argued that recent statements by the Company's chief executive officer to investors support a return on equity below 10%. For example, in October 2008 the chairman and CEO told investors that National Grid plc is an "extraordinarily low risk" company with very solid returns. Ex. DIV-70. Investors were further told that "[w]e are a very low risk business." Ex. DIV-69 at 6; Tr. 10/22/08 at 76. Without further evidence to show what "low risk" meant to the speaker making these statements, however, they have little probative value.

Based on all of the evidence presented, the Commission finds that 10.5% is a reasonable return on equity for the Company's Rhode Island operations. This return on equity is comparable to the U.S. average for natural gas utilities, with a slight upward adjustment in recognition of the market turmoil that has occurred since the Company submitted its filing in April 2008. Ex. NGrid 9 at 14-24 (Moul Rebuttal) (recent economic conditions which the Company believes will increase the cost of equity capital). The Commission has the discretion to grant a return on equity that brings the Company in line with other comparable utilities. *See Narragansett Electric Co. v. Harsch*, 117 R.I. 395, 368 A.2d 1194 (1977) (utility may be granted rate of return sufficient to bring its return in line with those currently achieved in the same region by entities with similar risks). A return on equity of 10.5%, when applied to the Company's

approved rate base, should enable the Company to serve its customers effectively and adequately compensate investors for risks assumed.[6]

3. Size of Rate Base.

The Company proposed a rate base of $285,241,458. Ex. NGrid-3 at 44 and Attachment NG-MDL-1 at 24. The Company's proposal was based on forecasted additions to plant in service of $36,679,000 in the twelve months ending September 30, 2008, and $60,780,000 in the twelve months ending September 30, 2009. Ex. NGrid-3 at 42-44 and Attachment MDL 1, p. 26 of 33. The Division proposed reducing average rate year plant in service by $10,259,000, resulting in a net rate base reduction of $9,980,000 to $275,261,000. NGrid Post-Hearing Mem. at 17.

Company Position. The Company argues that the budgeted expenditures for plant additions will be incurred. A lag in contractor billing is responsible for actual spending in the early months of the period running below budget. Tr. 9/9/08, at 9-10, 12 (Fleck). The Company further argues that the Division's adjustment incorrectly assumes that spending on additions is linear. The Company offers to update its responses to Data Requests DIV 1-2 and DIV 13-4 through October 2008 and represents that they would show that the gap between budgeted and actual spending is narrowing. NGrid Post-Hearing Reply at 20. The Company also represents that it does not object to an adjustment in the rate year end plant in service amount if the projected capital spending does not occur. *Id.* at 19.

Division Position. The Division reduced the proposed rate base after reviewing the Company's actual capital expenditures for the period October 2007 through March 2008, and determining that they were only $14.36 million, or 19.4% below budget. Ex. DIV-8 (Data

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[6] Commissioner Bray dissents from this portion of the Commission's decision and would adopt the Division's position for reasons stated on the record at the November 24, 2008 Open Meeting. Tr. 11/24/08 at 110.

Request DIV 1-2). Based on those actual expenditures, the Division asserts that the Company has overstated its forecasted capital additions in the 12 months ending September 30, 2008 by $5,282,000, and overstated forecasted capital additions for the twelve months ending September 30, 2009 by $9,954,000.

Commission Decision. At the hearings, the Company presented evidence that the budgeted expenditures will be incurred. Tr. 9/9/08 at 9-10 (Fleck). The Company's testimony that a lag in contractor billing is responsible for actual spending in the early months of the period running below budget was not rebutted. Tr. 9/9/08 at 9-10, 12 (Fleck). The Company also represented to the Commission that if it were to update its responses to Data Requests DIV 1-2 and DIV 13-4 through October 2008, it would show that the gap between budgeted and actual spending is narrowing. NGrid Post-Hearing Reply at 20; Ex. DIV-52. In addition, the Company represented to the Commission that it would not object to an adjustment in the rate year end plant in service amount if the projected capital spending does not occur. *Id.* at 19.

The Commission finds that the Division's position, while reasonable based on the information made available by the Company prior to the hearings, does not account for the lag in contractor billings in the early months of the measuring period, or the non-linear rate of spending on plant additions. The Commission therefore approves the Company's proposed rate year rate base. In the event that the projected capital spending does not occur prior to the end of the rate year, the Company shall notify the Division and make an appropriate adjustment to reflect the actual lower amount of actual plant in service.

B. Operating Expenses (Cost of Service).

1. Health Care Costs.

The Company proposed rate year medical and dental costs of $4,614,000, a 21.4% increase over the test year expense. Ex. NGrid-3 at 18 and Attachment NG-MDL-1 at 8

(Laflamme); Tr. 8/27/08 at 39. The Division reduced rate year health care costs by $907,456 based on seven months of actual data, which suggested that costs would be less than proposed by the Company. Ex. DIV-1 at 5-7 (Effron). The Company disagreed that seven months of data are adequate to calculate costs, but did not challenge the reduction. Tr. 9/8/08 at 84-85 , 101-102 (Laflamme); NGrid Post-Hearing Mem. at 20. The Commission approves the reduction of $907,456.

2. **FAS 112 Expense.**

FAS 112 relates to post-employment benefits other than pension, such as short term and long term disability benefits and health care costs associated with employees, their dependants and beneficiaries. The Company initially proposed an expense of $912,846. The Division challenged this amount on the grounds that some or all of the proposed expense appeared to be a "catch-up" of non-recurring prior year costs not appropriate to include in the rate base. Ex. DIV-2 at 2 (Effron); Ex. DIV-28 (Data Request DIV 13-2); Commission Record Request No. 5; Tr. 9/8/08 at 89-92, 94-96. At the hearings, the Company developed testimony indicating that a portion of its proposed FAS 112 expense is non-recurring. Tr. 9/8/08 at 91 (Laflamme). The Company revised its proposed FAS 112 expense from $912,846 to $740,000. Tr. 9/8/08 at 89-92, 94-96; Ex. NGrid-4, Attachment NG-MDL Rebuttal 2 at 3; Ex. NGrid-21 (NGrid Response to Data Request DIV 13-3).

The Division's witness agreed that FAS 112 expense is appropriate to include in the revenue requirement "assuming it's a normal, ongoing level of expense." Tr. 9/8/08 at 180 (Effron). The Division states that the proposed downward adjustment to $740,000 "is not unreasonable." Division Post-Hearing Mem. at 21.

The Commission finds that FAS 112 expense is a normal, recurring expense associated with employee benefits, and that the Company has removed any "catch-up" amount

resulting from an error in recording the Company's FAS 112 expense following the Southern Union transaction. The Commission further finds that the Company's estimated FAS 112 expense for FY 2009 is $740,000, which is representative of the expense level that the Company will experience on a going-forward basis.

3. Synergy Savings – Southern Union Merger.

In August 2006, National Grid acquired the Rhode Island operations of New England Gas company from Southern Union. The Company proposed adding $1,054,609 to its cost of service revenue requirement in this docket to reflect the Company's 50 percent share of asserted synergy savings from the merger. The adjustment included $896,971 of shared savings and $157,638 for amortization of costs to achieve. Ex. NGrid-3, Attachment NG-MDL-1; Ex. NGrid-4 at 13 and Attachment NG-MDL Rebuttal 4. The Company proposed including this amount in rates for 10 years. *Id.*

Company Position. The Company measured its proposed merger synergy savings by comparing three categories of corporate expense: employee compensation, administrative and general expense, and corporate office expense. The Company's approach was to look at changes in these categories because the merger did not combine operations. Pre-merger costs were measured during the year ending June 30, 2006. Post-merger costs were measured during the test year, ending September 30, 2007. Ex. NGrid-4, Attachment MDL Rebuttal-4 (calculating total demonstrated savings of $1,951,580); Tr. 9/8/08 at 75-76 (Laflamme).

The Company argues that using the Division's benchmark period (the year ending June 30, 2003) to calculate synergy savings is not appropriate because it does not account for three years of cost increases or decreases before National Grid acquired the business in 2006, for gas sales declines after 2003, or a significant increase in rate base from infrastructure investments. Tr. 9/8/08 at 104-107; Ex. NGrid-4 at 11-12 (Laflamme Rebuttal). The Company

contends that "the record is clear that cost levels in discrete cost categories are reduced from prior levels" after the merger. NGrid Post-Hearing Mem. at 25. The Company disputes that expenses in the year ending June 30, 2006 were unusually high, and asserts that in any event the unusual expenses cited by the Division were in categories (distribution maintenance and uncollectables expense) not relevant to the Company's merger synergy calculation. *Id.* at 26-28, 32-33. The revenue requirement approved in Docket No. 3401 was based in part on a review of anticipated consolidation savings in specific cost categories, and the Docket No. 3401 savings proof was not intended to quantify underlying merger synergies, but only to determine whether shareholders would be entitled to continue to claim 50% of those synergies in a future base rate case. *Id.* at 29-32.

Division Position. The Division argues that the Commission has never reviewed Southern Union's expenses incurred in the year ending June 30, 2006 to determine if they are appropriate for rate-making purposes, and that therefore those expenses should not be used as a benchmark for measuring synergy savings. Division Post-Hearing Mem. at 29; Tr. 9/8/08 at 168-171 (Effron). The Division also expresses reservations about the Company's approach of selecting only certain expense categories for purposes of calculating savings, on the grounds that it was more likely to present the merger in a favorable light than a broad measure of the cost of service. Division Post-Hearing Mem. at 27-28; Tr. 9/8/08 at 103. The Division asserts that the Commission has already approved a method of measuring synergy savings achieved by the former New England Gas Company that broadly measures changes in the cost of service. Using this method, no synergy savings have been demonstrated because the normalized post-acquisition cost of service exceeds the inflation adjusted and normalized benchmark cost of

service for the acquired Rhode Island natural gas operations established in Docket No. 3401 by about $12.4 million. Ex. DIV-1 at 14 (Effron Direct) and Schedule DJE-4.1.

Commission Decision. The Commission in the past has allowed a 50/50 sharing of net merger savings between ratepayers and the Company. The Company realizes its share of the savings by adding them to the cost of service. *See, e.g., New England Gas Company*, Docket No. 3401, Order No. 17381 (2002). The rationale for allowing sharing of synergy savings is that the savings would not exist for customers without shareholders being willing to incur the costs of the merger. Synergy savings are only appropriate, however, when there is an adequate basis for establishing that the savings have been achieved.

The Commission finds that the Company's method of comparing post-transaction cost of service to a pre-transaction cost of service for the twelve months ended June 30, 2006 is not appropriate in this case. The Company's expenses for that pre-transaction period were never approved for inclusion in the base rates, and might not be indicative of a reasonable, normal level of ongoing expenses. The Division presented testimony suggesting that at least some expenses incurred by the Company in its benchmark period ending June 30, 2006 may have been excessive. Tr. 9/8/08 at 170 (Effron). Other evidence supported the Division's position that selecting only certain expense categories to measure synergy savings could present the merger in a more favorable light than a broad measure of expenses: a Company witness testified that an alternative calculation based on a broader measure of expenses would reduce the synergy savings proposed by the Company by approximately $250,000. Ex. NGrid-23 and Tr. 9/8/08 at 111-115.

The Company has the burden of presenting sufficient evidence in support of a requested rate increase. R.I.G.L. § 39-3-12 ("At any hearing involving any proposed increase in any rate, toll or charge, the burden of proof to show that the increase is necessary in order to

obtain a reasonable compensation for the service rendered shall be upon the public utility."). In the absence of additional evidence from the Company supporting the reasonableness of its expenses during its benchmark period, the Commission finds that no National Grid/Southern Union merger synergy savings have been shown.

4. Synergy Savings – KeySpan Merger.

In August 2007, National Grid completed a merger with KeySpan Corporation, resulting in a combined organization serving approximately 3 million natural gas customers in four states. The Company proposed reducing the base rate revenue requirement by $2.45 million to reflect the ratepayer half of anticipated synergy savings from National Grid's acquisition of KeySpan, net of the annual amortization of the cost to achieve. Ex. NGrid-3 at 39-40 (Laflamme Direct); Ex. NGrid-4 at 14-15 (Laflamme Rebuttal). The Company proposed this reduction although it does not expect the full amount of savings to be achieved until the fourth year after the merger.[7] The Company also proposed that it should be allowed to fix its share of the synergy savings in future rate proceedings at the same $2.45 million. The Division accepted the up front synergy savings for ratepayers, but initially proposed that any future synergy savings for the Company be subject to proof. The Company objected to giving the ratepayers up front credit for synergy savings not yet achieved in the rate year ($1.2 million of the $2.45 million), while subjecting the Company to a savings proof. Ex. NGrid-4 at 39 (Laflamme Rebuttal).

At the hearings, the Company and the Division stipulated that merger savings totaling $6.4 million are projected to result from the National Grid/KeySpan transaction, and that the annual amortization of the cost to achieve the merger savings is $1.5 million. The Company and the Division also stipulated that $2.45 million should be included in the base rate revenue

[7] Ratepayers' 50% share of net synergies to be achieved during the rate year is $1.3 million. Ex. NGrid 4 at 14-15 and Attachment MDL Rebuttal 5.

requirement as a credit, to reflect the ratepayers' 50% share of the projected merger synergies net of costs to achieve. Tr. 9/8/08 at 71-72 (Laflamme). The stipulation further provides that the Company will be allowed to include its $2.45 million share of projected merger synergies as a line item in the cost of service in any rate case filed within five years after the Commission's order in this case. Tr. 9/8/08 at 70-73 (Laflamme). In any rate case filed after five years but within ten years, the Company's share of synergy savings from the KeySpan merger will be subject to a savings proof based on a comparison of pre-merger total O&M expense (escalated for inflation) to total rate year O&M proposed in the rate case. The pre-merger total operation and maintenance expenses for this calculation will be the adjusted per book expenses for the twelve months ended September 30, 2007 as reflected in this proceeding. The Company will for ten years be allowed to reflect its share of savings in annual earnings reports filed with the Commission for earnings sharing purposes. The Commission finds that the stipulated synergy savings will provide a direct benefit to ratepayers, and that putting off including the ratepayer share of KeySpan merger synergy savings in the rate base until a future rate case is not in the best interest of the Company's Rhode Island customers. The Commission approves the stipulation.[8]

The Company requested that the Commission allow it to create a regulatory asset in accordance with FAS 71 to account for the levelized amortization costs to achieve over a ten year period to be included in its cost of service. *Id.,* NGrid Post-Hearing Mem. at 36. The Commission finds that a regulatory asset pursuant to FAS 71 is a reasonable step ancillary to the approval of the synergy savings. The Commission approves this request.

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[8] Commissioner Holbrook dissents from this portion of the Commission's decision and would require that the synergy savings be determined in a separate docket for reasons stated on the record at the November 24, 2008 Open Meeting. Tr. 11/24/08 at 119.

5. Gas Marketing Program.

The Company proposed to establish a ratepayer-funded Gas Marketing Program and to include marketing program costs of $1,377,000 in the base revenue requirement: $698,798 for customer rebates and incentives, $528,000 for customer outreach and communication, and $150,000 for program administration. Ex. NGrid-6 at 25-26 (Mongan Direct); Ex. DIV-8 (Data Request DIV 1-20). The Division objected, and proposed an allowed marketing expense of $148,000.

Company Position. The Company states that it is proposing a Gas Marketing Program that will (1) expand the use of natural gas as a cleaner-burning fuel than heating oil alternatives, (2) maintain the overall throughput of the system so that the cost of the system is not carried by fewer and fewer units, and (3) operate at no cost to the system because revenues received from new customers will exceed the cost to add them. NGrid Opening Statement at 30; NGrid Post-Hearing Mem. at 37, 42. The proposed program will target residential and C&I customers located on the existing distribution system who do not use gas, or use only limited quantities (*i.e.*, residential non-heating customers). Ex. NGrid-6 at 4-5 (Mongan Direct). The Company projects 1,950 incremental residential conversions from the program in 2008 and has incorporated approximately $900,000 of revenues from these anticipated new customers in its revenue requirement calculations, as well as $550,000 of incremental rate base expense. Ex. NGrid-7 at 9 (Mongan Rebuttal); Ex. NGrid-6 Attachment SPM-1; Tr. 8/27/08 at 46.

In the Company's view, the Gas Marketing Program is needed to offset customers' up front cost of converting from oil to natural gas. The Company believes that this incremental investment poses a significant obstacle for many customers, regardless of any price differential between oil and natural gas. Ex. NGrid-6 at 10-11; Ex. DIV-17 (Data Request DIV 8-7); NGrid Post-Hearing Mem. at 39-40. The Company anticipates a 400% increase in Rhode

Island oil to gas conversions through the end of fiscal year 2009, resulting from the Gas Marketing Program and the oil/gas price differential. Ex. COMM-1 (Data Request COMM 1-23). This increase is much larger than in the Company's other jurisdictions where rate-funded gas marketing programs have existed for some time. *Id.*

The Company disputes that passing equipment discounts through to is customers, or offering equipment rebates, is discriminatory or anticompetitive. The record shows that the Company is purchasing of equipment in bulk from manufacturers who were the successful bidders in a competitive solicitation and is passing the competitive price made available by the manufacturer to all customers who are interested in procuring their furnace or boiler through the Company. Ex. DIV-3 at 28. The Company is not making any profit on the sale of equipment, nor is it adding any type of markup. *Id.* Moreover, all converting customers are eligible for the equipment rebate, regardless of whether they purchase their equipment through the Gas Marketing Program, or through a third-party plumbing and heating contractor. *Id.* Thus, the Company is purchasing the equipment at a market price following a competitive solicitation; is providing that equipment to converting customers at cost, and is offering equipment rebates to all converting customers on a non-discriminatory basis.

The Company also disputes that its ValuePlus Installer program improperly benefits its unregulated affiliate, National Grid Energy Services ("NGES"). The record shows that the only contact that the Company would have with NGES is through the ValuePlus Installer ("VPI") Program, which occurs because NGES is allowed to participate on the same basis as all other pluming and heating contractors. *Id.* The record shows that out of all the conversions completed through the program, approximately 30 percent utilize a referral through the VPI Program. *Id.* The record also shows that NGES handles only a small percentage (5% on

average) of the total conversions completed in any jurisdiction in which the company conducts the Gas Marketing Program. Thus, there is no record support for the conclusion that the Company's unregulated affiliate would be favored or would unduly benefit from the existence of the Gas Marketing Program.

The Company's internal rate of return calculation for new customers added through the Gas Marketing Program demonstrates that the program will benefit ratepayers by generating returns from new customers that exceed the Company's allowed return on equity. Ex. NGrid-6 at 23-24 (Mongan). The Company produced an internal rate of return calculation demonstrating that the addition of new residential customers through the Gas Marketing Program would produce a rate of return of approximately 14.8 percent, while new C&I customers will produce a rate of return of approximately 21.4 percent. *Id.* at 28. This calculation is significant because it means that, in this case, the Commission will aim to design rates to recover the Company's allowed return on equity but customer additions completed through the program will produce a rate of return in excess of that amount. Ex. NGrid-6 at 21-22 (Mongan). Since the Company is proposing to implement an earnings sharing mechanism to share earnings in excess of the allowed rate of return, customer additions resulting from the program will inure to the direct benefit of existing customers, who are credited with 50 percent of earnings in excess of return on equity and 75 percent of incremental earnings greater than 100 basis points above the allowed 10.5% return on equity.

The Company maintains that the Gas Marketing Program is not prohibited by Rhode Island law because it is designed to encourage gas conversions by (1) extolling the efficiency of gas furnaces and other major home appliances, (2) raising customer awareness regarding the amount of money consumers would save by using newer, efficient equipment

models, (3) providing informational materials that encourage the use of newer and more efficient gas appliances, and (4) encouraging conservation rather than merely promoting the use of gas. NGrid Response to Legal Memorandum on Gas Marketing Program at 15. Even assuming that the customer communications under the Gas Marketing Program are promotional, and therefore prohibited by R.I.G.L. § 39-2-1.2, rebates, discounts and staffing are not direct or indirect costs of advertising, and should be allowed. *Id.* at 16.

Even institutional and branding costs may be allowable, if there is a demonstrated customer benefit. NGrid Response to Legal Memorandum on Gas Marketing Program at 6. The Company has demonstrated that the Gas Marketing Program will directly benefit customers in both the near and long-term. *Id.* at 19, 23-24.

Division Position. The Division argues that the incremental growth in revenues that the Company estimates will arise from the Gas Marketing Program will still be achieved without it. Data for the first eight months of 2008 show 1,617 conversions and upgrades, a nearly 250% increase over the corresponding period in 2007. Ex. DIV-11, Response to Commission Data Request 3-8. Conversions in the first eight months of 2008 exceeded the annual conversions that the Gas Marketing Program seeks to achieve. Ex. NGrid-6, Attachment NG-SPM-1. The expense of the Gas Marketing Program is not necessary. The Company should be permitted to spend only an amount equal to the planned spending of Rhode Island oil dealers, $148,000. Ex. DIV-3 at 27 (Oliver).

The Division disputes the argument that the cost of adding the new customers targeted by the Gas Marketing Program exceeds the incremental revenue. The Company has focused its marketing effort on customers located near existing distribution mains. Because distribution mains represent the largest element of the Company's rate base, new customers who

do not require additions to distribution mains can be added to the system at less than the average cost on which rates will be based. Division Post-Hearing Mem. at 22.

The Division also argues that the Gas Marketing Program would result in ratepayer funds being used to benefit the Company's unregulated affiliate, National Grid Energy Services. National Grid Energy Services performs oil to gas conversions in competition with other plumbing and heating contractors. Tr. 10/20/08 at 201-04 (Mongan). The Company's practice is to refer customer conversion inquiries to contractors on its Value Plus Installer list, including National Grid Energy Services; therefore, increasing the number of oil to gas conversions directly benefits National Grid Energy Services along with other conversion contractors. To date, National Grid Energy Services has performed only a small percentage of all residential conversions in Rhode Island. The Division asserts that over time the unregulated affiliate will become the dominant beneficiary of the marketing expenses being paid by ratepayers.

The Division also argues that the Company launched the Gas Marketing Program with its own funds earlier this year, and is likely to continue it even without explicit cost recovery through rates. Current economic conditions argue against an increased rate burden for an unnecessary program. Furthermore, the program arguably violates R.I.G.L. § 39-2-1.2 because it is designed to promote the consumption of natural gas. Division Post-Hearing Mem. at 25-26.

Attorney General Position. The Rhode Island Attorney General states that the proposed Gas Marketing Program is prohibited by G.L. § 39-2-1.2(a), which does not allow expenses in the Company's rate base for "advertising, either direct or indirect, which promotes the use of its product or service, or is designed to promote the public image of the industry."

Advertising under the statute includes all forms of promotional media, as well as promotional activities including discounts, rebates, and sales administration. The Commission has disallowed promotional, goodwill and institutional advertising expenses, including labor expenses, in prior dockets. RIAG Post-Hearing Mem. at 2-7.

The Gas Marketing Program does not qualify for the statutory exemption allowing advertising "informational or educational in nature, which is designed to promote public safety and conservation of the public utility's product or service." R.I.G.L. § 39-1-1.2(a). Each component of the program promotes use of natural gas. RIAG Post-Hearing Mem. at 9-13; Ex. NGrid 6; Ex. AG-3; Tr. 10/23/08 at 163-173 (Oliver); Tr. 10/20/08 at 194-95 (Mongan).

The customer outreach and education component of the Program consists of a concerted marketing effort to convince a target set of potential customers to convert to natural gas over their existing "energy choice." Ex. NGrid-6 at 8-9, 11. Through direct mailings, radio, and visual media, etc., the Company represents to customers that they can "save money" (because gas is more "efficient" than oil) and "save space" (by "saying good-bye" to your old oil tank and the "soot, fumes, and sulfur dioxide" of oil). *See, e.g.* Ex. AG-3 at 3, 12, 18, 20, 22. The Company also represents that customers can "find help" locating a "qualified" contractor through the Company's VPI Program and earn "valuable rebates . . . up to $1,500 on heating equipment," a $1,500 discount "that'll make your [the customer's] wallet happier too." *See, e.g.,* Ex. AG-3 at 11-12, 15-16, 18. The stated purpose of these communications is to "identify potential conversion candidates" and to "pass those contacts on to local plumbing and heating contractors" participating in the Company's VPI program. Ex. NGrid-6 at 15-16.

The Program's customer outreach and education component is not tailored merely to inform customers about the benefits of natural gas in terms of efficiency and conservation.

Rather, the component functions to identify, and then to steer target customers who do not have relationships with contractors towards contractors who will convert their system(s) to natural gas (*e.g.*, typically an "on-main conversion or low-use upgrade") from the customers' existing energy sources. Ex. NGrid-6 at 16. The component, therefore, is purely promotional in nature.

Substantially all of the testimony in the record supports this conclusion. Mr. Mongan acknowledged that the direct mail materials that the Company forwarded to its customers in connection with the Program in late 2007 and early 2008 promote natural gas over oil in multiple ways: (i) by intimating that customers waste .30 of every dollar in oil heat; (ii) by invoking fears that with oil comes the ever-present worry of a leaky tank; (iii) by implying that purchasing natural gas (rather than oil) is more patriotic because 97.3% of it as opposed to 56% for oil "comes from North America;" and (iv) by stating that burning oil inevitably produces "fumes" and "greenhouse gases" that are not associated with natural gas. Tr. 10/20/08 at 195-197.

The second component of the Program – installation support and associated labor ($150,000) – violates § 39-2-1.2(a) for a similar reason. The VPI Program is a "contractor-referral system" that seeks "to facilitate the Company's efforts to increase system utilization in a cost-effective manner through low-use upgrades and on-main conversions," Ex. NGrid-6 at 17, and specifically, is designated to "create a high level of customer satisfaction and convenience," facilitating the Company's effort to "increase system utilization." Ex. NGrid-6 at 17. The principal aim of the VPI Program and associated incremental labor, is to promote natural gas over customers' existing energy sources and to promote the public image of natural gas.

The record evidence supports this conclusion. Mr. Oliver testified that in his expert opinion the VPI Program is promotional. Tr. 10/23/08 at 173. Mr. Mongan confirmed

that the Company had engaged an "in bound inquiry rep" as well as an "inside sales rep" to handle all conversion related calls. Tr. 10/20/08 at 194. Customers that require contractors are steered to the VPI network. Tr. 10/20/08 at 194-195. This serves the promotional aim of the gas marketing program: to facilitate customer conversions from other energy sources to natural gas. Tr. 10/20/08 at 194-195.

The equipment discount and rebate components of the Program also serve to promote the use of gas over customers' existing sources of energy. Ex. NGrid-6 at 18-19. Under the third component of the Program (equipment discounts), "purchased equipment is offered to customers . . . at a price that reflects both the Company's bulk-purchase discount and also a further discount made available through the [Program] to enable customer conversions to gas service." Ex. NGrid-6 at 18. "Because the cost of gas conversion can be higher than other fuel options available to the customer, the combination of the bulk purchasing discount and the program discount provide a valuable incentive to customers" to enable them to switch to gas service from their existing energy source. Ex. NGrid-6 at 18.

The same is true for equipment rebates – the fourth component of the Program. "Customers who would prefer to purchase gas-heating equipment from a manufacturer that is not part of the Company's bulk purchasing program" are "eligible for a rebate of equal value to the program discount offered on equipment purchased by the Company from its manufacturing suppliers." Ex. NGrid-6 at 18. This ensures that customers are able to obtain the same program incentive – the elimination of "incremental costs" – that "must be overcome in order to motivate new gas conversions." Ex. NGrid-6 at 19.

Most, if not all of the evidence on the record, corroborates the promotional nature of equipment discounts and rebates. Mr. Oliver testified that in his expert opinion, the rebates and discounts associated with the Program are promotional in nature:

> Q. Do you believe that those other components, . . . the rebates and discounts, that those have a characteristic that would advance one energy source over another?
>
> A. They tend to, yes.

Tr. 10/23/08 at 173. The equipment rebates and discounts, moreover, are directly marketed to customers in the customer outreach and education component of the Program. Tr. 10/20/08 at 197. Without the rebates and discounts, the other promotional components of the Program would not, and could not, function. Tr. 10/20/08 at 247-48.

The Company has not provided any analysis of the internal rate of return of the Gas Marketing Program in the absence of the price differential between oil and gas. The record supports the conclusion that the increase in conversions is the result of this price differential, not the Company's marketing program. The customer outreach and education component of the Program commenced in the last quarter of 2007. Ex. AG-3 at 1. For the first quarter of 2008, the Company completed 628 residential conversions – which the Company concedes "is a greater number of conversions than experienced in the past for the same period." Ex. NGrid-7 at 9. The Company projects 1,950 incremental residential conversions in 2008, all the while conceding that during this time period natural gas has enjoyed and continues to enjoy a substantial price differential advantage as compared with oil – a differential which "is currently motivating some customers to commence the conversion process . . . ." Ex. NGrid-7 at 11. The Company concedes, moreover, that many (but not all of) the conversions to date can be attributed to the cost differential and not the Program. Ex. NGrid-7 at 10; *see also* Tr. 10/23/08 at 160-61 (Oliver) (price differentials "very strongly suggest that not only today but in the long

run heating with natural gas would be a preferred alternative"). Therefore there is no clear evidence to show that the program will provide a direct ratepayer benefit, which in some other jurisdictions (but not Rhode Island) might justify the expense. RIAG Post-Hearing Mem. at 14-16.

The proposed program would be detrimental to ratepayers because (1) they would be paying the cost of identifying conversion opportunities for the Company's unregulated affiliate, (2) they would be funding the inside inquiry and sales representative activities that benefit the unregulated affiliate, and (3) they would pay for equipment discounts and rebates afforded to customers of the unregulated affiliate, without any contribution from the unregulated affiliate. RIAG Post-Hearing Mem. at 16-19.

Commission Decision. Regardless of the alleged economic, environmental or customer benefits of the proposed Gas Marketing Program, it must comply with Rhode Island law. In Rhode Island, base rates may not include a utility's expenses for "advertising, either direct or indirect, which promotes the use of its product or service, or is designed to promote the public image of the industry." R.I.G.L. § 39-2-1.2(a). The Commission has disallowed promotional, goodwill and institutional advertising expenses, including promotion-related labor expenses, in prior dockets. *See, e.g., Tariff Filing Made by the Providence Gas Company on February 16, 1995*, Docket No. 2286, Order No. 14589 (1995) (allowing informational expenses but disallowing promotional, goodwill and advertising expenses of $457,000); *Valley Gas Co. v. Burke*, 518 A.2d 1363, 1366 (R.I. 1986) (upholding Commission decision to approve informational advertising expenses and deny promotional advertising expenses). Advertising expenses are allowable only for advertising that is "informational or educational in nature, which

is designed to promote public safety and conservation of the public utility's product or service." R.I.G.L. § 39-1-1.2(a).

The Commission finds that the evidence presented in this docket demonstrates that the Company's Gas Marketing Program promotes the use of natural gas, contrary to R.I.G.L. § 39-2-1.2(a). Company testimony expressly linked the marketing program to increased gas consumption by existing low-use customers or new customers near existing distribution lines. For example, one Company witness stated:

> The basic objective of the Company's Gas Marketing Program is to encourage cost-effective, increased system utilization through conversions of new and existing low-use customers to gas service.

Ex. NGrid-8 at 4 (Mongan Direct); *see also id.* at 13 ("the Gas Marketing Program is targeted at motivating conversions to gas service . . . ."). The record also reflects that the Gas Marketing Program will benefit the Company's unregulated affiliate, National Grid Energy Services, by generating sales leads that will be shared with National Grid Energy Services along with other contractors participating in the Value Plus Installer program. Tr. 10/20/08 at 199, 235-236 (Mongan).

The Company's arguments that the Gas Marketing Program should be allowed because it entails advertising "informational or educational in nature, which is designed to promote public safety and conservation of the public utility's product or service," R.I.G.L. § 39-1-1.2(a), are not persuasive. It is unusual for gas distribution companies to market conversions with ratepayer funds, Tr. 10/21/08 at 144 (Oliver), and the Commission sees no basis to extend the definition of "informational or educational" activities to include activities aimed primarily at adding new natural gas customers to the distribution system. The Company launched the program with its own funds earlier this year, Tr. 10/22/08 at 60-61 (Stavropoulos), and

anticipates that it will produce high internal rates of return. Tr. 10/20/08 at 142 (Mongan). Current economic conditions argue against an increased rate burden for marketing efforts that were sufficiently beneficial to the Company that they were initiated without a ratepayer contribution.

The Commission further finds that the incremental rate year sales that the Company has estimated will be produced by the Gas Marketing Program should not be eliminated. Data for the first eight months of 2008 show conversions up nearly 250% over the corresponding period in 2007. Ex. DIV-11, Response to Commission Data Request 3-8. The Division presented testimony that over time, natural gas will hold a significant price advantage over oil that will encourage conversions. Tr. 10/21/08 at 66-72; Ex. DIV-3 at 20-21 (Oliver). This evidence supports the conclusion that the Company's estimated sales growth from conversions will be achieved even without a ratepayer funded Gas Marketing Program.

6. Uncollectible Expense.

The Division proposed reducing the Company's uncollectible accounts receivable expense of $3,594,522 by 50% of the cost of the proposed low income discount, or $415,000, if the proposed low income discount were adopted by the Commission. The Division presented testimony linking the proposed discount to a reduction in uncollectible accounts. Ex. DIV-3 at 72 (Oliver) ("This recognizes that a large portion of the [low income] discount amounts would likely become future uncollectible accounts expenses in the absence of the offered discounts, and it shares the risks associated with the effectiveness of those discounts between the Company and its ratepayers.").

The Company does not gather information from which it can determine the actual uncollectible rate for low income customers. However, the Company disputed that any link exists and presented evidence that uncollectible accounts for electric service have increased

notwithstanding a low income discount for electric ratepayers. Ex. NGrid-4 at 8-9 (Laflamme Rebuttal); Tr. 9/8/08 at 98-101 (Laflamme).

At the hearings, the Division and the Company stipulated that in the event the Commission approved a low income discount (of any size), uncollectible expense would be reduced by $150,000. Tr. 9/11/08 at 175-176 (Czekanski); Division Post-Hearing Mem. at 30. The Commission approves the stipulated $150,000 reduction.

7. **Rate Case Expense.**

The Company proposed that rate case expenses for the Company, the Division and the Commission be allowed through base rates, amortized over three years. NGrid Post-Hearing Mem. at 45. The record reflects that that Company will incur rate case expenses totaling $884,481; the Division will incur rate case expenses totaling $113,075; and the Commission will incur rate case expenses of $350,887; for a total rate case expense of $1,348,443. NGrid Response to Commission Post-Hearing Data Request Set 1; Division Response to Commission Post-Hearing Data Request Set 1; Tr. 11/24/08 at 93-94. The Commission finds that rate case expenses are a necessary cost for the Company and recovery of reasonable rate case expenses is allowed through base rates under the Commission's precedent. The Commission further finds that the expenses of the Company, the Division and the Commission are reasonable in light of the scope, complexity and novel policy issues of this contested rate case, as reflected in the voluminous record and lengthy public hearings. The Company shall be allowed to recover its updated rate case expenses, including the Division's and Commission's expenses, amortized over a three year period, or $449,481 per year.

8. **Encroachment Expense.**

The Company's pro forma rate year expenses included $1,054,000 for additional operation and maintenance expenses relating to encroachment by increased public works

activities and third party excavations. Part of the increased expenses were based on the backlog of work existing in early 2008, and part were based on anticipated new encroachments. Ex. DIV-12 (Division Data Request 4-10). After reviewing the Company's actual encroachment expenses for the five months ending February 2008, the Division concluded that the rate of encroachment spending was well below the level reflected in the Company's pro forma rate year expenses and recommended a reduction of $756,000. Ex. DIV-1 at 9 (Effron). The Company accepted this recommendation. Division Post-Hearing Mem. at 27. The Commission approves the $756,000 reduction to the Company's pro forma test year operation and maintenance expense for encroachments, to $298,000.

9. Distribution Maintenance.

The company incurred actual distribution maintenance expenses of $16,804,000 in the test year. However, these expenses included costs incurred to reduce the backlog of Grade 2 gas leak repair work and paving restoration work arising before the beginning of the test year. Ex. DIV-1 at 10 (Effron); Ex. DIV-8 (Division Data Request 1-28); Ex. DIV-18 (Division Data Request 9-3); Ex. DIV-18 (Division Data Request 9-4). The Division concluded that the increased test year distribution maintenance expenses related to the backlog reduction were not continuing expenses, and recommended a reduction of $539,000 to the Company's pro forma test year operation and maintenance expense for distribution maintenance. Ex. DIV-1 at 11 (Effron). The Company accepted this position. Ex. NGrid-4, Attachment NG-MDL Rebuttal 1. The Commission approves the $539,000 reduction, and allows $16,265,000.

C. Revenue Reconciliation Proposals

1. Accelerated Capital Replacement Program

The Company proposed an accelerated replacement program ("ARP") to make upgrades to targeted portions of its delivery system. More specifically, the ARP will remove all

high pressure, bare-steel services from inside customer premises within five years. Tr. 9/9/08 at 42-44 (Fleck). The ARP will increase the amount of bare steel mains replaced annually, from 7.5 to 18 miles. Tr. 9/9/08 at 42-44 (Fleck). The Company also proposed to replace small-diameter cast iron mains on a more systematic basis. Ex. NGrid-5 at 17-21 and Attachment NG-SLF-1 (Fleck).

The Company initially proposed that the total cost of main replacement be funded through a reconciling mechanism. The Division objected that only the incremental cost of the accelerated replacement program, above pipeline replacement costs that would be incurred in the ordinary course, should be reconciled. The Company accepted this change. Ex. NGrid-4 at 17-18 (Laflamme Rebuttal); Tr. 9/8/08 at 78-83. The Company also agreed to limit upward rate adjustments for the accelerated replacement program if the Company's earnings are at or above its approved return on investment. *Id.* The Company states that its planned incremental spending is about $12 million, out of about $25 million total spending planned. Ex. NGrid-4, Attachment NG-MDL Rebuttal 6; Tr. 9/8/08 at 149-151 (Laflamme).

Company Position. The Company distributes natural gas to approximately 250,000 Rhode Island customers through a distribution infrastructure that includes approximately 900 miles of cast iron main, 440 miles of unprotected bare steel main and 240 miles of unprotected coated steel main out of a total 3,100 miles of main. Ex. NGrid-5 at 4, 15-16 (Fleck); Tr. 9/9/08 at 6-7 (Fleck); Ex. COMM-3 (Data Request COMM 2-7). Approximately 50% of the Company's Rhode Island distribution assets are leak prone, and the number of gas leaks is increasing. Since 2005, there have been over 1,400 gas leaks per year in the system, more than 50% higher than the leak rate of 900 per year for 1991-2004. Ex. NGrid-5 at 15-16 (Fleck). The leak rate has increased in spite of the fact that the Company and its predecessors

have replaced almost 120 miles of bare and unprotected coated steel mains in the last ten years. *Id.* The number of leaks per mile is higher in Rhode Island than in other jurisdictions where the Company operates. Ex. NGrid-5 at 16 (Fleck). For example, leakage rates in Rhode Island are more than seven times higher than in upstate New York. Tr. 9/9/08 at 73 (Fleck).

The Company has conducted a baseline assessment of its distribution assets and determined that at current replacement rates, continual system degradation from corrosion will undermine its ability to meet demand and operate the system safely and reliably. Ex. NGrid-5 at 16 (Fleck). The Company therefore proposed an accelerated replacement program ("ARP") to make upgrades to additional sections of its delivery system, selected based on such factors as the age and condition of the pipe, geographic location and expected growth in system demand. Ex. NGrid-5 at 17 (Fleck). The Company anticipates that its accelerated replacement plan will cause the number of gas leaks to begin to decline. A declining number of gas leaks is a reasonable measure of overall system safety and is the Company's goal. Tr. 9/9/08 at 26 (Fleck).

The Company also proposed removing all high pressure, bare-steel services from inside customer premises within five years. Approximately 8,261 such services exist today, which historically have been replaced at a rate of approximately 500 per year. The Company plans to accelerate the removal rate to approximately 1,600 units per year. Ex. NGrid-5 at 21 (Fleck). High pressure bare steel inside services need to be replaced because of the risk of corrosion where the high pressure gas line passes through the wall into the customer's basement. There is no way to inspect that part of the high pressure pipe. *Id.*; Tr. 9/9/08 at 141 (Ledversis). A survey conducted in the Company's Long Island territory demonstrated there is a resulting potential for failure and leaks. Tr. 9/9/08 at 43-48 (Fleck).

The incremental cost of the ARP, above pipeline replacement costs that would be incurred by the Company in the ordinary course, will be funded through a reconciling mechanism. The Company's planned incremental spending on the ARP is about $12 million , out of about $25 million total main replacement spending planned. Ex. NGrid-4, NG MDL Rebuttal 6; Tr. 9/8/08 at 149-151 (Laflamme). The incremental expense being proposed by the Company is based on safety concerns, not economic considerations. Tr. 9/9/08 at 164 (Laflamme).

Division Position. The Division supports the ARP in light of the documented growth in gas leaks in the distribution system, Tr. 9/9/08 at 135 (Ledversis), but suggests that (1) depreciation expense reductions related to ARP related plant retirements should be recognized; (2) the depreciation rate of mains and services, not the average composite rate, should be used to calculate incremental depreciation expense; (3) the calculation of incremental property tax expense should be modified so that it is based on the prior year's annual property tax expense to net plant in service; (4) the mechanism should apply to accelerated replacements, not routine replacements; and (5) there should be no rate adjustment if the Company is earning at or above its authorized return on equity. The Company has agreed to these modifications. Ex. NGrid-4 (Laflamme Rebuttal testimony at 17-18); NGrid Post-hearing Mem. at 49.

Commission Decision. The Commission finds that gas leaks create undesirable safety and environmental issues, and increase costs for ratepayers on account of lost commodity. Tr. 9/9/08 at 164 (Laflamme). The record reflects that historic pipeline replacement rates are not keeping pace with Rhode Island's aging gas distribution infrastructure, and that accelerated infrastructure replacement is in the interest of the ratepayers and the public as a whole. Ex. NGrid-5 at 16 (Fleck) (Rhode Island leaks per mile are increasing and are higher than in other

Company jurisdictions); Tr. 9/9/08 at 73 (Fleck). The Company's proposed increase in the annual replacement of distribution mains and its five year plan to remove high pressure inside services reasonably balances the need to measurably improve the safety and reliability of the Rhode Island natural gas distribution system in the near term against the burden to ratepayers of increased rates to pay for accelerated replacement. A reconciling mechanism is appropriate for the substantial incremental cost of the Company's proposed infrastructure improvements.

The Commission therefore authorizes the Company to implement the ARP, subject to the modifications recommended by the Division. Beginning in January 2009, the Company will submit a proposed implementation schedule to the Division each January for comment, and secure Commission approval. The Company will also submit a reconciliation report for each fiscal year. The first ARP reconciliation report for the 12 months ending March 31, 2009 will be submitted by May 15, 2009 for a rate adjustment effective July 1, 2009. The ARP will entitle the Company to a rate adjustment only to the extent of the capital cost that is incremental to the amount included in base rates in this proceeding. Tr. 9/8/08 at 79-83, 152-153 (Laflamme).

2. Gas Supply Related Bad Debt Cost.

The Company proposed to increase the portion of commodity cost bad debt embedded in the rate base from 2.1% to 2.46%, based on a five year average. Tr. 9/8/08 at 122-123 (Laflamme). The Company also proposed to recover or return any variance from the uncollectible ratio fixed in base rates through the GCR on a reconciling basis. Anticipated commodity related bad debt is currently fixed in base rates.

Company Position. Commodity bad debt is a component of the gas cost that should be recovered on a pass-through basis, as is the cost of the commodity itself. The change in policy will be beneficial to customers because the current structure locks in relatively higher

bad-debt recovery ratios, as well as relatively lower ratios, depending on circumstances at the time of a base-rate filing. Tr. 9/8/08 at 121-123 (Laflamme). The reconciliation would be based on the most recent five year average for net bad debt write-offs as of June 30 of each year. *Id.*; Ex. NGrid-15 at 13. Because the reconciling mechanism would apply only to bad debt related to commodity costs, and not bad debt related to distribution costs, the Company would still have a strong incentive to improve the uncollectible ratio. *Id.*

Division Position. The Division opposes a bad debt reconciliation mechanism because annual reconciliation would amplify price volatility for customers. Ex. DIV-3 at 79 (Oliver). The Commission has historically used a multi-year average of the Company's actual experience in base rates in order to mitigate year to year variations. Division Post-Hearing Mem. at 44; Ex. DIV-3 at 74-75, 79 (Oliver).

Commission Decision. The Commission finds that a bad debt ratio of 2.46% for base rates is supported by the record. The Commission declines, however, to approve the proposed gas cost-related bad debt reconciling mechanism. The Commission has historically used a multi-year average of the Company's actual experience in base rates in order to mitigate year to year variations, and finds that annual reconciliation of commodity-related bad debt cost is not in the best interest of ratepayers because it has the potential to amplify price volatility for customers. Ex. DIV-3 at 74-75, 79 (Oliver). Fixing the commodity-related bad debt ratio in base rates is not inconsistent with the Commission's treatment of commodity costs, which are recovered on a pass-through basis, because the Company has the ability to develop and implement measures to lower the uncollectible ratio.

3. Reconciliation of Pension and PBOP

The Company proposes to reconcile its pension and post-retirement benefits other than pension ("PBOP") expenses annually, and to adjust charges to ratepayers up or down accordingly to recover or return amounts above or below actual costs.

Company Position. Pension and PBOP expenses are volatile and beyond the Company's control because they respond to actuarial assumptions and financial market performance. They should be reconciled annually for several reasons.

First, a reconciliation mechanism will not reduce the Company's incentive to control benefit costs. The record shows that the principal alternative for reducing pension costs is the establishment of a defined contribution plan to replace the historical defined benefit plan. Tr. 9/8/08, at 138-139, 249. The record also shows that the Company has already taken steps to reduce pension costs that are within its control by preventing new employees hired after 2002 from entering into defined benefit pension plans. *Id.* at 139. Specifically, on January 1, 2005, all non-union new hires were placed in the Valley Gas pension plan design, which had a less generous formula for its participants. Ex. DIV-15 (Data Request DIV-6-22). Also, on January 1, 2005, post-retirement dental coverage for future non-union retirees was eliminated. Since National Grid's acquisition of the regulated gas operations in Rhode Island in August 2006, all non-union new hires were placed in the National Grid cash balance pension plan. *Id.* Lastly, effective March 31, 2008, all non-union employees that were covered under the Valley Gas or the Providence pension plan designs were transferred into the National Grid Final Average Pay pension plan. *Id.* Lastly, the Company has established an annual review process for pensions and PBOPs centering on: (a) actuarial assumptions, (b) vendor performance, and (c) medicare prescription drug program refund administration. *Id.* There is no basis to conclude that a reconciliation mechanism for pension and PBOP expenses will deter the Company from

continuing to make efforts to control the costs of these benefits and the Company has already made the change identified as the most significant opportunity for reducing costs, which is the transition from a defined benefit to defined contribution plan.

Second, the Company has demonstrated that the magnitude of pension expense as compared to the overall revenue requirement is great enough to warrant reconciliation. The pension and PBOP expense will account for approximately 6.4% of the Company's overall proposed revenue requirement of $150 million. Ex. NGrid-4, at 20. Contrary to the Division's assertions, this is a significant amount of expense for the Company to manage and it is as yet unclear what the impact of current market conditions will be on the pension and PBOP trust fund balances and resulting liability.

Third, the Company has demonstrated that the level of volatility for pension and PBOP is greater than other O&M expenses. Pension/PBOP expense and funding is subject not only to variation from year-to-year, but also is susceptible to periods of extraordinary fluctuation as a result of circumstances in the financial markets, which have been experienced in the recent years. Ex. NGrid-4, at 21. Fluctuations in the value of pension assets cause variations in pension and PBOP expense and funding levels. These volatile fluctuations are due to the stock market and are similar to the wild fluctuations in commodity prices like gas. In fact, both fluctuations in stock market prices and gas prices are beyond the control of the Company. Tr. 9/8/08 at 223-224. As an example of the volatility, contributions to the pension fund increased from $1,350,000 for the plan year ended December 31, 2002 to $2,858,158 for the plan year ended December 31, 2003 and totaled $5,388,000 for the plan year ended March 31, 2008. Ex. DIV-8 (Data Request DIV-1-8). For PBOP, information regarding funding, if any, is unavailable for the years under Southern Union ownership from 2003 through 2007, but the record shows

that National Grid made a contribution of $4,307,000 for the fiscal year ended March 31, 2008. Ex. DIV-8 (Data Request DIV-1-9). Thus, pension and PBOP expenses and funding can change dramatically from one year to another.

Fourth, the amount of pension and PBOP expense included in rates is not calculated to provide adequate funding without the need for a reconciliation mechanism. Fluctuations in the value of pension assets resulting from stock market changes leads to variations in pension and PBOP expense and funding levels. As a result, it is extremely difficult to establish a representative amount of expense in rates, especially where circumstances are occurring in the financial market that will impact the pension and PBOP plans beyond what is included in the expense levels that would be included in rates in this proceeding without a reconciling mechanism. In that regard, the present approach to funding pensions and PBOP creates a potential mismatch of what is embedded in rates for the FAS 87 and FAS 106 expense and what is actually contributed to the pension and PBOP funds. For example, for fiscal year ended June 30, 2004, $6,263,958 was expensed but only $3,626,754 was required for contribution by Southern Union for the plan year ended December 31, 2004. *Id.*

To ensure adequate funding of the pension fund and the PBOP in the future, a fully reconciling mechanism is the best approach because under the operation of the proposed mechanism it would assure that whatever the Company recovers from customers for FAS 87 or FAS 106 is actually contributed to the pension and the PBOP funds or reserved for in order to provide customers with an equitable economic benefit. Ex. NGrid-4 at 23. Without a reconciliation mechanism, there will inevitably arise a situation when the Company is recovering pensions and PBOP costs in base rates and contributing to the funds at a different level. *Id* at 24. Thus, a reconciliation mechanism will ensure that the Company funds the pension and PBOP

funds at the same level as amounts collected from customers. *Id.* Otherwise, there will be occasions when the Company will collect more in rates than it is required to contribute for pension and PBOP or the reverse.

It should also be noted that the proposed reconciliation mechanism for pension and PBOP is consistent with the Commission's recent directive in new England Gas Company, Docket No. 3690, Order No. 18780, which stated that "it is the long-term interest of ratepayers to have a properly funded pension fund." In that case, the Commission noted the mismatch between contributions to the pension fund and what is expensed for pensions over a number of years under New England Gas, and stated that this "difference . . . could be harmful to the pension fund in the long tem." A reconciliation mechanism is the best solution to this mismatch. Not surprisingly, in response to a question from the Commission concerning the possibility of an unfunded pension liability growing under the current rate structure, the Division's witness acknowledged: "[t]hat's the funding mechanism." Tr. 9/8/08 at 236-237. A reconciliation mechanism is the best funding mechanism to avoid an unfunded liability from growing for pension or PBOP.

Division Position. Reconciliation mechanisms are generally contrary to sound ratemaking principles, except for costs with large fluctuations beyond the Company's control that jeopardize its financial integrity. The Company has not presented evidence of the volatility of its pension and PBOP costs, or shown the potential of such costs to impair its financial integrity. Almost all other expenses in the Company's base cost of service are also subject to fluctuation. Division Post-Hearing Mem. at 30-31. Pension and PBOP expenses should be treated differently than GCR because gas costs are comparatively far greater, and therefore pose a far greater risk of a substantial under-recovery. Tr. 9/8/08 at 216-17, 221-24 (Effron).

Reconciliation is not needed to provide adequate funding for pensions and PBOP. Expense accruals are already calculated to provide adequate funding of the programs, even without a reconciliation mechanism. The pension program is currently 97% funded. Tr. 9/8/08 at 142 (Laflamme). This shows that the current method of regulation has not resulted in inadequate funding, and that annual reconciliation of pension and PBOP expense is not necessary. Tr. 9/8/08 at 245 (Effron).

Authorizing annual reconciliation would shift risk to the ratepayers. Tr. 9/8/08 at 217 (Effron). It also would reduce the Company's incentive prudently to manage its PBOP expenses. The Company has moved to reduce pension expense by instituting a defined contribution plan for new employees and making other changes. Tr. 9/8/08 at 139-140 (Laflamme); Ex. DIV-15, NGrid Response to Division Data Request 6-22. The Division questions whether the Company would have undertaken these pension cost control measures if a pension and PBOP cost reconciliation mechanism had been in place. Division Post-Hearing Mem. at 33.

Commission Decision. While the Commission in general disfavors reconciliation mechanisms, they have been approved in the past for certain items. For example, the Company recovers its commodity costs through a reconciliation mechanism. The Commission has also approved a reconciliation mechanism for unpredictable and potentially costly environmental remediation measures. Ex. NGrid-4 at 22 (Laflamme Rebuttal). While not as large as commodity costs, the Commission finds that the Company's pension and PBOP expenses are sufficiently large and unpredictable to justify an annual reconciliation mechanism. The record reflects that these expenses can be subject to substantial fluctuations as a result of changes in the

financial markets that affect pension asset values, and that these fluctuations are beyond the Company's control. Ex. NGrid-4 at 21 (Laflamme Rebuttal).

The Company's pension program is currently 97% funded. Tr. 9/8/08 at 142 (Laflamme). However, the record suggests that under the current methodology, its predecessor, Southern Union, may have funded pensions at the minimum tax deductible level rather than contributing the full amount approved in rates. Tr. 9/8/08 at 135 (Laflamme). For the fiscal year ended June 30, 2004, $6,263,958 was expensed but only $3,626,754 was required for Southern Union's contribution for the plan year ended December 31, 2004. Ex. DIV-8 (Data Request DIV 1-9); NGrid Post-Hearing Mem. at 56. A reconciling mechanism will give ratepayers greater assurance that the Company is funding pension and PBOP funds at the same level as amounts collected from customers.

Under the Company's proposal, ratepayers would assume the risk of investment losses currently borne by shareholders. Tr. 9/8/08 at 136-137 (Laflamme). However, since 2002, new Company employees have been placed in a defined contribution plan, mitigating this risk. *Id.* at 139-140; Ex. DIV-15, NGrid Response to Division Data Request 6-22. The Company has also taken other steps to reduce future pension and other benefit expense, including placing employees in less generous plans and eliminating post-retirement dental coverage for future non-union retirees. Ex. DIV-15 (Data Request DIV 6-22). The Company plans to make further efforts to control pension and PBOP costs regardless of whether the reconciling mechanism is approved: for example, the Company has established an annual review process for pensions and PBOP expenses to assess actuarial assumptions, vendor performance and medicare prescription drug program refund administration. *Id.*; NGrid Post-Hearing Mem. at 53-54; ; Tr. 9/8/08 at 147-148 (Laflamme). Therefore, the Company's exposure to pension

investment losses has been reduced in recent years, and the proposed reconciling mechanism does not create unreasonable new risks for ratepayers.

Reasonable pension and PBOP expenses are legitimate and unavoidable costs of operating the distribution system. To the extent that fixing pension and PBOP expenses in the base rates leads over time to the pension being underfunded, current ratepayers are effectively shifting greater pension and PBOP expense to future ratepayers. The Company's proposed reconciliation mechanism more closely matches present rates with present pension and PBOP expense, and is in the interest of ratepayers. The Commission approves the Company's proposed pension and PBOP mechanism.[9]

D. Revenue Decoupling

The Company's filing proposed to implement for the first time in Rhode Island a full revenue decoupling mechanism ("RDM"). As initially proposed, the RDM applied to all firm rate classes, with certain exemptions for new large customers. Ex. NGrid-12 at 2-7 (Simpson). The Company thereafter modified its proposal to exempt the four large and extra large firm rate classes. Tr. 9/12/08 at 5-6. Low income customers were subsequently excluded as well. Tr. 10/22/09 at 8-11; NGrid Post-Hearing Mem. at 62-63. The remaining classes (residential non-heating, residential heating, small C&I and medium C&I) include most of the Company's customers and generate more than 80% of the Company's distribution revenue. Ex. NGRid 15 Appendix NG-PCC-3; Tr. 9/26/08 at 167-168.

The RDM would set a target revenue per customer amount for customers in the affected classes. The target revenue per customer would be set at an amount sufficient for the Company to recover the base rate revenue requirement for that customer class approved in this

[9] Commissioner Bray dissents from this decision and would adopt the Division's position for reasons stated on the record at the November 24, 2008 Open Meeting. Tr. 11/24/08 at 78-80.

rate case. To the extent actual revenue per customer in the affected classes exceeded or fell short of the target, the surplus or shortfall would be credited or collected through an annual adjustment of the DAC.

The Company's decoupling proposal generated substantial briefing and testimony at the hearings from the parties and intervenors. The principal arguments presented for and against decoupling are summarized below.

Company Position. The Company argues that decoupling will "eliminate the Company's dependence on gas consumption to obtain necessary revenues to run the business," and will "allow [it] to aggressively promote conservation through new energy efficiency, without harming revenues." Company Opening Statement, at 29. Natural gas usage per customer has steadily declined, and the declines are expected to continue. Ex. NGrid-12 at 15-17 (Simpson). Because of declining usage per customer, the Company asserts that traditional ratemaking no longer works. Declining usage deprives the Company of revenues that have been allowed by the Commission as reasonable and prudently incurred. Ex. NGrid-2 at 18 (Stavropoulos).

Decoupling is "a vehicle for recovery of the revenue requirement approved in this case," NGrid Post-Hearing Mem. at 64, and nothing more. Decoupling will not insulate the Company from cost increases occurring in the normal course of business, some of which are highly sensitive to inflation, including labor, construction materials, and fuel costs. Therefore, the Company has the same incentive to reduce costs that it would have without decoupling. *Id.* at 65-66.

The Company disputes that the period of time that has passed since the last rate case demonstrates that the Company does not need an annual decoupling adjustment. The timing of this rate case is attributable to a rate freeze in effect through June 2005 and the transition of

ownership from Southern Union to National Grid. *Id.* at 69. The Company has not achieved its authorized ROE since fiscal year 2005, and declining gas usage per customer accelerated in 2004-2006. NGrid Post-Hearing Mem. at 70. The Company would not have made its authorized ROE from 2005 through 2008 even with decoupling. *Id.*

The Company also disputes that (1) weather normalization adjustments, higher fixed charges or declining block rates are alternatives to decoupling, (2) decoupling is unnecessary in light of state energy efficiency mandates, (3) decoupling will produce large annual rate increases for customers, and (4) decoupling will reduce customer incentives to conserve.

First, weather normalization, higher fixed charges, and declining block rates do not eliminate sensitivity of the Company to reduced revenues due to conservation (Tr. 10/23/08 at 180), which is demonstrated by the fact that all of these items were in place for the Company over the past five years and did not have the effect of maintaining revenues in the face of declining consumption. This is because higher fixed charges and declining block rates maintain a level of revenues despite declines in consumption but do not eliminate the impact caused by a reduction in use per customer. Tr. 10/22/08 at 99. Moreover, weather normalization does not protect against conservation, it simply operates to eliminate weather-related deviation from *average* from period to period. Over time, the cumulative weather normalization adjustments should approach zero as cumulative period to period weather approaches *average*. Ex. NGrid-13, at 31; Tr. 10/22/08 at 47. Also, a rate-design structure with higher fixed charges reduces the price signal to consumers to conserve. Tr. 9/26/08 at 172; Tr. 10/23/08 at 73. Thus, decoupling is the best means to generate the allowed level of revenues in the face of declining consumption, while maintaining appropriate price signals to customers.

Second, the record shows that decoupling will remove the disincentive for companies to reduce sales and has the potential to align the interests of utility with conservation. Tr. 9/29/08 at 164-165; Ex. TEC-RI-1, at 19. The record also shows that disincentives have a significant influence on utility policies and that utilities are key players in promoting conservation. Tr. 10/23/08 at 68, 73-74. The implementation of decoupling will encourage the Company to use its full expertise and resources to reduce customer usage. In contrast, although the utility will conduct a state-mandated program to the best of its ability, it has a disincentive to go beyond the confines of that program to promote conservation on a creative or aggressive basis. Tr. 10/22/08 at 28. Also, the incentive the Company receives for its gas DSM program is relatively small in terms of removing the Company's concern about revenues on a system-wide basis. *Id.* at 32.

Third, under traditional ratemaking, there are fewer, but larger rate increases, while decoupling increases occur on an annual basis to a lesser amount. Tr. 9/26/08 at 177. For instance, TEC-RI's expert witness agreed that the increase due to decoupling would be approximately $500,000 in 2007 and about $1,000,000 in 2008, and that these increases for 2007 and 2008 are relatively small. Tr. 9/29/08 at 92, 94-5. Cost increases of that size occur now with weather normalization. For example, weather normalization led to an increase of $927,000 in 2006 and $882,000 in 2007. Ex. TEC-RI-3 (Data Request TEC-RI 1-7). Thus, the concern regarding large annual increases is unfounded.

Fourth, decoupling will not reduce the incentive to conserve. Under the Company's decoupling proposal, customers will still be billed based on consumption, and the annual decoupling rate adjustment will be added or credited to the DAC. In addition, the decoupling rate adjustment is based on billed delivery charges only, where commodity revenues

account for 2/3 of the customer bill. Tr. 9/26/08 at 121-23. In the unlikely event that all residential heating customers installed conservation measures that reduced usage by 10 percent, which would theoretically produce a decoupling rate adjustment that would offset the delivery charge benefits of the conservation measures, the typical residential heating customer would still realize savings on the GCR portion of his bill, which is 70 percent of the bill. The average savings would be 4.7 percent or $71.43. Ex. NGrid-13, at 18-19. In addition, the decoupling rate adjustment will also be based on consumption which could also produce a price signal encouraging conservation. Thus, the record shows that in practical application the decoupling rate adjustment will not offset the delivery rate savings a customer would receive from conservation in addition to the GCR savings the customer will enjoy as a result of conservation.

Division Position. Decoupling has been approved in only a limited number of jurisdictions, mostly within the last two years. There is not much evidence of its impacts on ratepayers. This would be the first approval of decoupling for a gas utility in New England, and the first for National Grid in the U.S. Rhode Island would be an experimental starting point for the Company. Division Post-Hearing Mem. at 45, 48.

The Company already has at least four types of revenue decoupling included in its tariff: (1) a weather normalization adjustment; (2) declining block rates for residential heating and small commercial and industrial customers; (3) demand charges for medium, large and extra large commercial and industrial customers that are adjusted to reflect usage in the prior winter; and (4) the use of a future test year to reflect known reductions in consumption. Full revenue decoupling is not necessary or desirable. Divison Post-Hearing Mem. at 53; Ex. DIV-3 at 5; Tr. 10/24/08 at 9-10.

There is no evidence that full decoupling will produce energy conservation beyond what could be achieved under existing DSM programs. The Company has in the past systematically touted the success of DSM programs and its own commitment to executing cost-effective and innovative conservation programs. The Company is capable of maintaining its commitment to carry out what the Commission has already ordered and what state law mandates without a decoupling mechanism. Division Post-Hearing Mem. at 45-48, 53. A commitment to "reach for the stars" in the future is not a sufficient basis to order decoupling. *Id.* at 49, 53. Ratepayers will pursue energy efficiency regardless of whether decoupling is adopted. *Id.* at 53.

The Company's decoupling mechanism insulates the Company against revenue declines for any reason, not just conservation efforts. It essentially reduces the Company's revenue risk to zero. By divorcing Company performance from revenues, it shifts responsibility to the Commission to ensure that appropriate system and service quality are maintained. Revenue erosion from DSM is already reflected in rate year billing determinants, so the Company does not need decoupling to earn a fair return. Division Post-Hearing Mem. at 48-49; Tr. 10/8/08 at 24 (Czekanski).

Had revenue decoupling been in effect since the last rate case, the Company would have been insulated from revenue losses resulting from the "serious distraction" of the Southern Union and KeySpan mergers. There is evidence that the Company would have received an additional $34.1 million over the four year period with decoupling. Division Post-Hearing Mem. at 49-51; Tr. 9/26/08 at 100.

Approval of an annual reconciliation for accelerated pipeline replacement expenses mitigates any concern that traditional ratemaking procedures will not allow the Company to invest in infrastructure. *Id.* at 51.

Approving full decoupling raises complex issues regarding how to apply a weather normalization adjustment to rate classes exempted from the decoupling mechanism. If full decoupling is approved, the Commission's only option is to allow service to classes exempted from decoupling without any weather normalization adjustment. Division Post-Hearing Mem. at 54 n. 127.

Traditional regulation works. The Company has an appropriate incentive to exercise prudent cost management, and can periodically apply for a rate increase if necessary. This allows the Commission to review revenues and expenses together. Decoupling could potentially weaken Commission oversight of the Company by making rate cases more infrequent. *Id.* at 53. Decoupling will also discourage rate case settlements that could involve rate freezes or rate caps. Tr. 8/27/08 at 164.

Environment Northeast. ENE supports the proposed RDM, as modified. Full decoupling will help achieve the state's economic, energy efficiency, and environmental goals by better aligning the Company's financial incentives with customer and public policy interests in maximizing investment in efficiency efforts that are cheaper than supply. Under the current tariff, the Company derives a significant portion of its revenue through volumetric distribution rates. The Company therefore has an economic disincentive to support programs that would result in the reduction of gas consumption. The RDM would eliminate this disincentive for included rate classes. Because a portion of the distribution revenue would continue to be collected through volumetric rates, customers will still have an economic incentive to conserve on both the commodity and distribution parts of the bill. ENE Post-Hearing Mem. at 3-5. California has had a long, successful history with decoupling. Massachusetts has recently adopted it. *Id.* at 19-20

The Company is in a unique position to effect positive ratepayer decisions regarding efficiency investments, and can do so more forcefully with decoupling. State law already authorizes the Company to administer gas efficiency programs funded through a volumetric charge. R.I.G.L. § 39-2-1.2(d). State law recognizes that DSM programs may affect utility revenues and authorizes a rate adjustment clause to provide for full recovery of reasonable and prudent costs of a company implementing conservation procurement. R.I.G.L. § 39-1-27.7(d). The proposed RDM is consistent with this law because it would allow full recovery, and disallow over-recovery, of such costs. ENE Post-Hearing Mem. at 12-15.

State law authorizes utility efficiency programs, but does not mandate the level of investment or parameters of the programs. ENE Post-Hearing Reply at 5. Decoupling will encourage the Company to favor practices that promote efficiency and conservation, including advocating for tighter codes and standards, pushing technological improvements, and shaping the competitive marketplace for more efficient products. *Id.* at 3, n. 7. Rhode Island's per capita natural gas consumption (excluding usage for electric generation) is 37th in the country, and there are still a great deal of energy efficiency investments that are less costly than supply. *Id.* at 2-3, 5. While some customer conservation will occur without decoupling, there is strong evidence that utility DSM programs are important to remove cost barriers, perceived technology risks and information gaps that impede conservation. *Id.* at 5.

Existing so-called "partial" decoupling mechanisms such as weather normalization do not eliminate the Company's sensitivity to sales volumes. Decoupling does not guarantee Company profits. The Company will need to manage its costs carefully to earn its allowed return. The Company's motivation to reduce expenses and be efficient will be the same. *Id.* at 16-17; ENE Post-Hearing Reply at 6-7.

Excluding the four large rate classes from the RDM addresses ENE's concern that applying decoupling to small, heterogeneous rate classes could have unintended negative consequences. *Id.* at 18; ENE Post-Hearing Reply at 7-8. The RDM's design also eliminates any risk of cross-subsidization among classes. ENE Post-Hearing Mem. at 19; Tr. 9/12/08 at 10.

Conservation Law Foundation. CLF supports decoupling. Climate change is a crucially important issue to which the Commission should pay attention. Decoupling eliminates the disincentive to conservation and efficiency that exists in traditional ratemaking and aligns the utility's incentives with the public interest. CLF Post-Hearing Mem. at 3-6. State utility commissions in North Carolina, Ohio, Maryland, New York and Massachusetts have recognized the disincentive to promote energy conservation under traditional ratemaking and have ordered decoupling in recent dockets. CLF Proposed Findings of Fact at 10-12.

Traditional ratemaking does not work today as it has in the past because of declining gas use. As a result of declining use, the Company has been deprived of revenues allowed by the Commission. This has had an impact on safety because the funds are needed to operate the distribution infrastructure. The Company's proposed RDM true-ups ensure that the Company will receive its revenue requirement, neither more nor less. Moreover, the Company proposes maintaining the earnings sharing mechanism so that the Company and customers will share in earnings that exceed the allowed ROE. CLF Proposed Findings of Fact at 4-6.

Energy conservation and efficiency that would be fostered by decoupling will reduce overall gas consumption and benefit ratepayers by helping them avoid embedded carbon costs that will in the future be part of commodity prices. Reduced emissions of carbon dioxide will also ameliorate climate change. *Id.* at 8-9. CLF has opposed the Company in other dockets, but supports it here.

CLF disputes that the proposed RDM will erode incentives for customers to conserve energy. Approximately 70% of a ratepayer's bill is the commodity charge, which will decline in direct proportion to declining use. The remaining 30% is the distribution charge, which is also collected volumetrically. Even if the distribution rate increases because of the RDM adjustment, it would be offset by declining volume usage. *Id.* at 12-13.

TEC-RI Position. TEC-RI opposes decoupling. Decoupling is a major departure from traditional ratemaking, and can have a significant impact on ratepayers. NGrid Response to TEC-RI data request 1-7; NGrid Response to data request TEC 1-77 (15 states have approved decoupling). If decoupling had been in effect over the past four years, ratepayers would have paid an additional $34 million. Tr. 9/26/08 at 100; TEC-RI Post-Hearing Mem. at 13.

The Company has presented no evidence demonstrating that decoupling would produce more energy efficiency. It presented no new energy efficiency proposals to be implemented in Rhode Island, or efficiency studies from other jurisdictions with decoupling. Rhode Island already has the lowest energy use per capita, and ranks high in per capita utility energy efficiency spending. Decoupling is not needed, as indicated by the Company's request to withdraw its decoupling proposal from this rate case. TEC-RI Post-Hearing Mem. at 15; Tr. 9/8/08 at 5-7 (denying motion to withdraw).

Decoupling is not mandated by R.I.G.L. § 39-1-27.7(a)(2)(d). That statute (1) applies only to electric utility distribution, (2) permits, but does not require, adjustment, and (3) only allows rate adjustment for costs of system reliability, energy efficiency and conservation procurement, not for revenue changes regardless of the cause as allowed by the Company's proposed RDM. TEC-RI Post-Hearing Mem. at 16. The proposed RDM shifts risk from the Company to the ratepayer, but does not compensate ratepayers for assuming this risk. *Id.* at 17.

If decoupling is approved, large and extra large rate classes should be excluded. These classes have small numbers of customers and large variability in revenues among customers. Small changes in class membership could result in RDM adjustments that are not related to conservation efforts. Excluding these classes would not lead to cross-subsidization because RDM adjustments are calculated by class. No party opposes excluding large and extra large customers from the RDM. TEC-RI Post-Hearing Mem. at 10-11.

Office of Energy Resources. Rhode Island Office of Energy Resources opposes decoupling. OER states that "the record does not provide either a logical or a legal basis for adopting the proposed decoupling adjustment at this time." OER Post-Hearing Brief at 2; OER Post-Hearing Reply at 4 (there is "no empirical evidence to define the weight and nature of the claimed disincentive"). OER also states that the Company has already accounted for known and measurable future lost volumes in its rates, *id.* at 3, and that it has the management tools to offset any alleged disincentive to promote gas efficiency. *Id.* at 4. The record does not show why the Company cannot overcome any existing disincentive to promote conservation with existing management tools. OER further states that R.I.G.L. § 39-1-27.7(d) authorizes, but does not mandate, a decoupling adjustment. *Id.* at 5.

No customers support decoupling. Large and extra large C&I customers and low income customers have convinced the Company to exclude them. The remaining customers, represented by the Division, do not support decoupling. OER Post-Hearing Reply at 7.

Wiley Center. The Wiley Center opposes the Company's RDM, which shifts to ratepayers the risk of lost revenue from drops in usage regardless of the cause of those drops, and does not provide for a commensurate reduction in the Company's rate of return. If decoupling is approved, low income customers should be excluded. Low income customers cannot afford to

pay more for gas service. The RDM will result in an increase in the cost of gas service for the foreseeable future, as gas usage is decreasing. Wiley Post-Hearing Mem. at 9-10; Ex. Wiley 1 at 10 (Pre-Filed Direct).

Attorney General. The Attorney General adopts the Division's position on decoupling. Opening Remarks of the Attorney General at 1. Should the Commission adopt decoupling, however, the Commission should exclude low income residential heating and non-heating customers from the RDM. RIAG Post-Hearing Mem. at 1 n. 1.

Commission Decision. The record reflects that consumption of natural gas per customer has been declining since at least 1980. Ex. NGrid-12 at 28-29 and Attachment NG-JDS-4 (Simpson Direct). Some of the reduction in consumption is related to passive conservation measures, such as the forced replacement of old, failing gas appliances with new models that a re more energy efficient. Ex. NGrid-12 at 18 (Simpson). Other reductions are the result of active conservation measures, often in response to commodity price increases. *Id.* at 20-21. The impact on natural gas utilities of declining use per customer over the years has apparently been manageable with traditional ratemaking, under which gas utilities facing substantial usage declines are free to apply for a rate increase. It is clear that the Company's inability to earn its allowed return on equity in recent years is as attributable to the Company's own business activities as to declining use per customer. The last rate case involving the Company's Rhode Island natural gas operations was Docket No. 3401 in 2002. In the settlement of that rate case, the Company's predecessor agreed to a rate freeze until June 30, 2005. The Company cited its merger activity in 2006 and 2007 to explain its failure to request a base rate increase in those years. Tr. 9/12/08 at 90-95 (Simpson).

The Company states that the "primary reason for the Company's [decoupling] proposal is to advance the goal of achieving greater energy efficiency in the State of Rhode Island." Ex. NGrid-2 at 13 (Stavropoulos). Yet there is little or no evidence in the record to demonstrate how or why this would occur. The Company has not identified any new conservation or energy efficiency initiatives that it would undertake in the event that decoupling were approved. No party presented any study or analysis of additional energy efficiency that decoupling would produce in Rhode Island.

The Company's incentive or disincentive to embrace conservation initiatives in the absence of decoupling was the subject of conflicting testimony. A Company witness testified that incentives influence utility behavior, and that decoupling would cause the Company to reach for the stars in developing new conservation initiatives. Tr. 10/22/08 at 28 (Stavropoulos). Certain intervenors also testified that decoupling could be expected to induce the Company to more aggressively pursue conservation and energy efficiency. Tr. 10/23/08 at 68-69, 88 (Kaplan). On the other hand, the Division's expert witness testified that while decoupling might affect the Company's behavior, it would not necessarily have any impact. The Division's expert suggested several reasons why financial incentives might not affect the Company's behavior at all. Tr. 10/21/08 at 208 (Oliver).

The fact that decoupling may eliminate a disincentive for the Company to promote conservation, even if true, does not necessarily translate into any significant reduction in consumption above what would have been achieved as a result of local and national economic pressures, technology improvements, and other extrinsic factors. Regardless of decoupling, most customers will have an incentive to conserve because reduced usage translates directly into lower

commodity charges for the customer, and commodity costs currently account for over two thirds of the average residential bill.

Revenue decoupling would protect the Company from revenue declines attributable to any cause, not only energy conservation and efficiency efforts. Ex. DIV-5 at 37 (Rothschild) (decoupling would "significantly reduce the non-diversifiable risks exposure to NG investors by a revenue stream that would be essentially unaffected by swings in economic conditions in the service territory."). Decoupling would reduce the Company's revenue risk to zero, and shift the risk of revenue variations to ratepayers. Tr. 10/22/08 at 76 (Stavropoulos). While the record includes substantial evidence of the benefits of decoupling to the Company, the evidence that decoupling will benefit ratepayers is largely speculative. Indeed, the record reflects the significant financial impact on ratepayers that decoupling might have. Over the last four years, revenue decoupling would have resulted in an additional $34 million of payments to the Company. Ex. TEC-RI-3 (NGrid Response to TEC-RI Data Request 1-7); Tr. 9/26/08 at 100 (Simpson) ("If the revenue decoupling mechanism had been in effect for all rate classes the net effect would have been the $34 million that Mr. Farley calculates.").

The Company is already protected from revenue variations caused by unusually cold or warm weather, through the weather normalization adjustment. It is also allowed to adjust demand charges for medium, large and extra large commercial and industrial customers based on usage during the prior winter. The Company is also allowed to recover its commodity cost and, as a result of this docket, to reconcile its expenses for pension and PBOP costs and for the accelerated capital replacement program. These mechanisms already protect the Company against unanticipated revenue shortfalls in many areas, and mitigate the need for full decoupling.

Certain intervenors emphasize that other utility regulators have approved decoupling, and suggest that the Commission should follow their example. *See, e.g.*, CLF Post-Hearing Mem. at 10-11. The decisions of other regulatory bodies are not evidence that decoupling would materially contribute to energy conservation and efficiency in Rhode Island. Over time, the adoption of decoupling in other states may produce concrete evidence of ratepayer benefits that could reasonably be expected to occur in Rhode Island, but that has not yet occurred.

After careful consideration of the evidence and arguments presented by the parties and intervenors, the Commission finds that the Company has not carried its burden of proof on the proposed RDM. The parties agree that full revenue decoupling would be a significant change in traditional ratemaking policy in Rhode Island. To adopt full revenue decoupling, the Commission needs more than speculative assertions that it would promote additional conservation or energy efficiency. The record reflects that decoupling is still relatively new and untested in the United States, having only been approved by fifteen states, many of them within one to two years. Ex. TEC-RI-3 (NGrid Response to data request TEC 1-77); *see* Ex. CLF-3 (Mass. Department of Public Uitlities); Ex. CLF-5 (North Carolina Utilities Commission); Ex. CLF-7 (Maryland Public Service Commission); Ex. CLF-8 (New York Public Service Commission). The impact of full decoupling on utility behavior and on ratepayers is not clear.

Traditional ratemaking has worked well in the past. The Commission is responsible for reviewing utility operations, and a full base rate case where witnesses are subject to examination and cross-examination is a valuable opportunity to look at the entire operation of the Company. Revenue decoupling may have the undesirable consequence of further enlarging

the period between rate cases, thereby reducing public oversight. The Commission is not persuaded that experimenting with full revenue decoupling is appropriate at this time.[10]

E. Low Income Discount.

The Company proposed a 10% discount off of Commission-approved customer and distribution charges for low-income residential heating and non-heating customers eligible for LIHEAP assistance. Approximately 16,000 heating customers and 2,500 non-heating customers would be eligible. NGrid Post-Hearing Mem. at 92; Ex. NGrid-30 (tariff changes). The Company estimates that average savings for a low income residential heating customer would be approximately $54 per year. The estimated impact of the proposed 10% discount is approximately $800,000 to be recovered from other firm customers. The Company proposed that the cost of the discount be allocated based on consumption, although it had no objection to a different allocation method. Tr. 9/11/08 at 160 (Czekanski); NGrid Response to TEC-RI Record Request No. 1.

Company Position. The Company believes that a 10% low income discount reflects the proper balance between the interests of poor customers and other ratepayers. Tr. 9/11/08 at 159-160, 164-165 (Czekanski); Ex. DIV-13 (NGrid Response to Division Data Request 5-19). The 10% low income discount would supplement other existing assistance for low income customers. For the twelve months ending June 30, 2008, $9,108,481 was available to help reduce the bills of low income gas customers. NGrid Response to Record Request No. 21. In addition, $983,643 was available to support low income customers' energy efficiency efforts. *Id.*

[10] Commissioner Holbrook dissents from this portion of the decision and would allow full revenue decoupling for reasons stated on the record at the November 24, 2008 Open Meeting. Tr. 11/24/08 at 13-24.

Division Position. The Division takes no position on the proposed 10% discount on the grounds that the appropriate level for low-income rate assistance "is a highly subjective matter . . . and [the Division] is not in a position to render an opinion regarding the reasonableness or appropriateness of either the proposed rate discount levels . . . ." Ex. DIV-3 at 69 (Oliver).

TEC-RI Position. TEC-RI does not object to the 10% discount. However, TEC-RI opposes allocating the cost to other ratepayers based on class consumption. Under this method, rates for non-residential customers will be increased twice as much as rates for residential customers to pay for the low income discount. This method is different than the methods used by the Company in New York and Massachusetts. TEC-RI proposes that the cost of the discount be allocated to rate classes using a rate base allocator (class rate base as a percent of total rate base). TEC-RI Post-Hearing Mem. at 22, 25.

Wiley Center Position. The Wiley Center proposes a low income discount of 50%. The economic crisis has deepened since the 10% discount was proposed. The annual out of pocket cost of utilities for the average low income household, taking LIHEAP and other assistance into account, is around $990 for gas and $823-$900 for electricity. This is about 13% of a minimum wage earning customer's wages, and 24% of the amount of assistance provided to a family of four on public welfare. Wiley Post-Hearing Mem. at 1, 5-6.

A low income discount is permissible under R.I.G.L. § 39-2-5(2) if it is "just and reasonable" or "in the interest of the public," and is not "unjustly discriminatory." The record shows that (1) the hardship borne by low income customers has worsened over the years, (2) low-income customers have been more severely affected by recent increases in commodity costs than other customers, (3) the discount may lessen the cost of terminating and restoring low

income customers, benefiting other ratepayers, and (4) other ratepayers may benefit as well from the stipulated $150,000 reduction in uncollectible expense. Wiley Post-Hearing Mem. at 2-4. The discount may also produce indirect ratepayer benefits from reduced health and public safety costs, and increased economic and educational productivity of low income customers. Ex. WC-1 at 9, WC-2 at 1 and App. 4. The impact on other residential and small and medium C&I customers ($2.21/year, $3.05/year and $26.28/year respectively on average, assuming the cost is spread volumetrically as proposed by the Company) is small. Ex. WC-3 at Data Request 1-8.

Utility regulators in Massachusetts, New Hampshire and Maine have added new protections for low income customers. In September 2008, the Massachusetts Department of Public Utilities ordered utilities to increase low income gas and electric discounts immediately, and the New Hampshire PUC increased the amount that other customers would pay to support tiered low income electric discounts. In August 2008, the Maine PUC increased funding for its electric low income assistance program by 13%. Wiley Post-Hearing Mem. at 7-9.

Attorney General's Position. The Attorney General "believes that the proposed discount is appropriate and reasonable in light of the value of the company's existing program and the substantial price increases that heating customers have experienced over the past year." Opening Remarks of the Rhode Island Attorney General, at 2.

The Commission possesses express statutory authority under R.I.G.L. § 39-2-5(2) to grant free utility service upon such conditions as the utility may impose, and may grant special rates to any special class or classes of persons so long as the rates are just and reasonable or in the public interest and are not unjustly discriminatory. The provisions of R.I.G.L. § 39-2-5(13) do not limit this authority. The expenses associated with the proposed low income discount are just and reasonable; the discount is not unjustly discriminatory; and the discount is in the public

interest. The Commission should allow all expenses associated with the discount as proposed. RIAG Post-Hearing Mem. at 20-27.

Commission Decision. The record evidence establishes that utility costs are a heavy economic burden for many Rhode Islanders, particularly those with very low incomes. The Commission finds that the proposed 10% discount offers a just and reasonable level of relief for the poorest Rhode Islanders, and is not unjustly discriminatory. For an average low income residential heating customer, the savings will be $49 per year. NGrid 11/26/08 Compliance Filing Attachment NG-Compliance RD-3, page 1 of 4. The Commission finds that the Wiley Center's proposed 50% discount is not supported by the record. All Rhode Islanders are facing unusually difficult economic times, and the approximately $800,000 cost of the 10% discount will be funded by other ratepayers, who in some cases may be only slightly better off than the discount recipients. The cost of the 10% low income discount to residential heating customer may be only a few dollars, but is only one of many increasing costs that cumulatively can be significant. Greater discounts face a heavier burden of proof of reasonableness, in light of their increasingly disproportionate benefit to the low income class and greater impact on other ratepayers to whom the cost of the discount is shifted.

The cost of the discount will be collected from other ratepayers based on consumption, as proposed by the Company. The Commission does not agree that TEC-RI's proposal to allocate the cost of the discount based on class revenue is appropriate.[11]

The Commission does not have the authority to require the Company to contribute shareholder funds to the proposed discount. The Company has made a voluntary contribution of $200,000 to the Good Neighbor Energy Fund, an amount that is equal to approximately 25% of

[11] Commissioner Holbrook dissents from the Commission's decision to approve the 10% low income discount and would refer this issue to the Rhode Island General Assembly, for the reasons stated on the record at the November 24, 2008 Open Meeting. Tr. 11/24/08 at 82-85.

the estimated cost of the discount that will be paid by ratepayers. The Commission urges the Company to consider increasing the amount of its voluntary contribution from shareholder funds to match the ratepayer funds that are being collected on account of the discount.

The Rhode Island General Assembly has in the past established a statewide energy affordability program, but the program was never funded and has now been repealed. The Commission would welcome the renewal and funding of that program. The Commission believes that a statewide energy affordability program approved and funded by the Rhode Island General Assembly would provide more accountability and, possibly, more resources for the energy costs of low income Rhode Islanders. The Commission's discretion to allow discounts is limited by the statutory requirement that any discount is just and reasonable and not unjustly discriminatory.

F. Non-Firm Tariff Issues.

1. Pricing for Non-Firm Transportation Customers.

Non-firm customers have dual-fuel capability, and agree that their gas service may be interrupted by the Company. Under the current "value of service" tariff, non-firm transportation service pricing changes monthly based upon the amount the customer would pay for its alternative fuel less a discount related to the customer's volume of consumption. The Company proposes maintaining the present "value-of-service pricing" for non-firm transportation customers, capped at 150% of the applicable firm service rate. The Division and certain intervenors propose "cost of service" pricing for interruptible service instead. The cost of non-firm service would be calculated based on a set discount off of the cost of firm service.

Company Position. The current tariff employs value of service pricing for non-firm customers. The tariff sets prices for non-firm customers such that the cost of the distribution charge and commodity charge combined is at a discount of between 2.25% and 22%

off the cost of the non-firm customer's alternative fuel (subject to a floor price of 10 cents/Dth in summer and 16 cents/Dth in winter). Value of service pricing acts as an incentive for non-firm customers to use gas distribution capacity that would otherwise be wasted, while simultaneously maximizing revenue for firm customers. The revenue impact of moving from value of service to cost of service pricing could be substantial for firm customers. Ex. NGrid-36; Tr. 10/8/08 at 6-17 (Czekanski).

As of September 1, 2008, there were 32 active non-firm service accounts. NGrid Response to Division Record Request No.-6. A preliminary engineering review conducted by the Company shows that 12 non-firm service customers can not be served as firm customers without system enhancements. *Id.* The estimated cost of the enhancements to bring a particular non-firm customer on line ranges from $9,000 to $3 million, depending on the customer. The estimated total investment needed to offer firm service to all existing non-firm customers is at least $9 to $10 million. *See* NGrid Response to Division Record Request No. 7.

The Company does not support a cost based rate for non-firm customers because a cost-based rate would normally include the cost of building and maintaining the system to meet the needs of all firm customers at peak periods. Allocating all of the system costs to firm customers implies that the cost of serving non-firm customers is equal to the marginal cost of service (primarily certain administrative costs). The Company disputes that marginal cost of service is an appropriate basis for setting non-firm rates, except to establish a floor for the least possible price that a non-firm customer should be paying. NGrid Post-Hearing Mem. at 84-85.

The Company also disputes that an embedded cost study is an appropriate basis for setting non-firm rates. An embedded cost study for non-firm customers requires judgments and assumptions about the assignment of costs that are inherently arbitrary. The embedded cost

studies produced by Company in this case demonstrate how different assumptions produce different results. NGrid Post-Hearing Mem. at 86-87; Ex. NGrid-38; Ex. NGrid-39.[12] Further, non-firm customers are not committed to the system and thus there is no assurance that costs allocated to the non-firm class will be recovered. NGrid Post-Hearing Mem. at 87.

Establishing a cost-based rate in the form of a discount off of firm service is not desirable because it will create an incentive to avoid taking firm service and does not allow for downward adjustment of the non-firm rate in the event that oil prices fall below natural gas. *Id.* The Company anticipates that a significant number of customers that migrated from non-firm to firm service in the past year would remigrate if a fixed, cost-based rate were established.[13] This would be poor ratemaking policy since it would have the effect of encouraging less use of the system. *Id.* at 88.

The Company argues that its proposed 150% cap is the best alternative for meeting the important ratemaking goals of (1) encouraging throughput regardless of the magnitude of price difference between gas and alternative fuels, (2) ensuring that firm customers receive an adequate benefit from non-firm use, (3) ensuring that non-firm pricing is fair and reasonable, and (4) ensuring that non-firm pricing does not undermine the integrity of the firm service rate or facilitate the avoidance of economical firm service. NGrid Post-Hearing Mem. at 90; Tr. 10/8/08 at 40-41, 112-115 (Czekanski); NGrid Response to Division Data Request 6-26.

Value of service pricing is not unjust or unreasonable because, with the exception of a few customers in capacity constrained areas of the system, it is the customer's choice to take non-firm service. Current non-firm pricing reflects the value to certain customers of being able

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[12] The Company's response to data request DIV 5-53 (Ex. DIV-13) calculates non-firm COSS at $1.3 million, or $0.81/decatherm.

[13] Data request DIV 6-5 and 6-6 refer to transfers from non-firm to firm service.

to opt in and opt out at any time without making a firm commitment to the gas distribution system. NGrid Post-Hearing Reply at 21. A fixed discount is flawed because if there is no possibility that the system would lose non-firm throughput – as might be the case when the price of alternative fuels is high -- there is no reason for the Company to extend a discounted price to non-firm customers. *Id.* at 22.

Division Position. The Division proposes setting rates for non-firm transportation service at a fixed discount of 20% off of the customer's otherwise applicable firm rate (to be computed by dividing the sum of the projected variable distribution charge revenue and demand charge revenue for the customer's otherwise applicable rate class by the projected annual therms of gas use for the otherwise applicable firm rate class for the rate year). The Division also proposes establishing a revenue requirement of $2.856 million for the non-firm rate class, based on the Company's November 5, 2008 revised cost of service study, and revising the proposed joint stipulation regarding revenue reconciliation for non-firm service to provide that revenue above $2.856 million is split 75/25 between firm and non-firm customers. Division Post-Hearing Reply at 7-8.

TEC-RI Position. It is unjust and unreasonable to set non-firm distribution rates to maximize revenue because the Company is a monopoly. Non-firm pricing should be based on cost of service. Witnesses for both the Company and other parties testified that, because non-firm service can be interrupted on days when system capacity is constrained, non-firm customers impose very low demand costs. As stated by the Company,

> This result occurs largely because the actual 'cost' of providing non-firm service is minimal. Since the system is constructed and maintained to ensure uninterrupted service to firm customers on a year-round basis (i.e., through the peak winter periods), distribution capacity is available in the off-peak periods for use by non-firm customers at little or no additional cost.

Ex. NGrid-16 at 5 (Czekanski Rebuttal). The Company also testified that "[w]e design rates that are expected to cover the full cost of service. So essentially the firm customers have paid for all the firm capacity that we provide and make available." Tr. 10/22/08 at 19-20 (Stavropoulos). Rhode Island Hospital's expert testified that

> The direct costs and marginal costs are the only real costs that are caused by non-firm customers because the company, in its planning, does not add capacity to its distribution system in order to serve non-firm customers.

Tr. 10/22/08 at 206 (DeMetro).

TEC-RI argues that it is reasonable to infer that the Company's proposed floor for non-firm rates ($0.10/Dth summer, $0.16/Dth winter) is a good proxy for the marginal cost of non-firm service. The Company's November 5, 2008 embedded cost of service calculation results in a unit cost of $0.92/Dth, but uses the same demand cost allocation for non-firm customers as for firm customers. This is not a fair or reasonable reflection of demand cost causation because non-firm customers are interrupted on peak demand days. Ex. DIV-49 (number of non-firm curtailments from 2004-2008). Non-firm customers should be allocated 50% of the demand costs. This results in a non-firm class cost of service of approximately $1.8 million based on the Company's estimated usage volume. TEC-RI Post-Hearing Mem. at 4-8.

A non-firm class cost of service of $1.8 million is consistent with the revenue requirement that would be associated with the estimated $9-10 million investment necessary to serve all non-firm customers as firm customers. Record Request DIV-7; TEC-RI Post Hearing Mem. at 8-9.

Non-firm transportation rates should be set at a fixed 40% discount to firm rates. This produces $1.8 million of revenue on the 3.1 million Dth of volume the Company used in its November 5, 2008 cost of service study. TEC-RI Post-Hearing Mem. at 2, 9.

The Commission issued an order over a year ago asking for a cost of service based rate for non-firm service. The Company did not comply, and the Division also has not produced a cost of service based rate. The best record evidence supports the 40% discount off of firm rates proposed by TEC-RI and Rhode Island Hospital. TEC-RI Post-Hearing Reply at 2.

Rhode Island Hospital Position. The current non-firm tariff has produced dramatic and unpredictable changes in the Hospital's energy costs and unreasonably high prices over the past two years. RIH proposes that the Commission order a modified cost of service approach that would establish non-firm pricing at a discount off of firm pricing. The discount would set non-firm prices at a level that is more representative of the historic level of revenues collected from this class. RIH Post-Hearing Mem. at 1-2, 10-12.

Non-firm customers receive service only if there is excess capacity on the distribution system. The Company has not invested in the infrastructure that would be needed to serve non-firm customers as firm customers, an estimated expense of at least $9-10 million. The value of gas service is highest when demand is greatest. Rates charged to non-firm customers should be lower than those charged firm customers to reflect the less valuable service received. Instead, they are significantly higher; 400% higher in September 2008. RIH Post-Hearing Mem. at 5-7.

Under R.I.G.L. § 39-2-1, utility rates must be just and reasonable. Current non-firm rates do not meet this requirement because they bear no relationship to either firm rates or the cost of providing non-firm delivery service. The Company's proposed cap for non-firm rates at 150% of firm rates is arbitrary and unsupported by any reasonable rationale. The Company is using a cost based method to design rates for firm customers, but not non-firm customers. *Id.* at 7-9.

The non-firm cost of service studies presented by the Company are flawed because the Company allocated the demand-related costs of serving large firm C&I customers to non-firm customers. At most, non-firm customers should be allocated 50% of the distribution system demand costs calculated by the Company. Including allocated customer and commodity costs, non-firm customers should contribute $1.8 million to cost of service. This is representative of the historic level of revenues collected from the non-firm class. Based on Exhibits NGrid 36, 38 and 39, setting non-firm rates at a 35-40% discount off of firm rates would collect at least that target amount of revenue. RIH Post-Hearing Mem. at 10-12.

RIH's proposal would not skew rates for other classes. It is based on the Company's cost of service studies showing that revenues of $1.8 million from non-firm ratepayers would be a substantial contribution to distribution costs. This amount would be credited to firm rates, as is done currently. RIH disputes that non-firm customers are not committed to using natural gas. Non-firm customers have incurred and continue to incur substantial costs to maintain the capacity to burn gas, for both economic and environmental reasons. RIH Post-Hearing Reply at 3-4.

The current non-firm tariff is unreasonable and is creating undue and unnecessary hardships for a number of the state's largest employers at a time of economic uncertainty and high unemployment. Value of service pricing is producing rates significantly above the cost of serving non-firm customers and four times higher than the approved rates for firm customers. The extreme volatility of value of service pricing also makes it unfair and unreasonable. In 2008, value of service costs for RIH and other extra large high volume customers ranged from $0.10/Dth to $2.83/Dth. RIH Post-Hearing Reply at 3. The Company's proposed cap does not yield just and reasonable rates. RIH Post-Hearing Mem. at 13-14.

RIH strongly opposes the Company's revenue neutrality stipulation, which for purposes of the DAC increases the base level of non-firm contribution to $2.8 million. If the Commission does not accept the Company's proposal to cap non-firm rates at 150% of firm rates, this could result in a continuing surcharge to firm ratepayers. RIH proposes that the Commission instead direct the Company to remove the additional $1.2 million of former non-firm revenues assumed in developing firm billing determinants and provide it as a credit to DAC, with true-ups. RIH Post-Hearing Reply at 5-7.

Silent Sherpa Position. Silent Sherpa proposes setting the non-firm tariff based on a marginal cost of service analysis. The distribution system is bought and paid for and delivered to firm ratepayers. It would be redundant to charge the non-firm ratepayers for the same service. Tr. 9/29/08 at 229 (Grasso); Tr. 10/8/08 at 174-175.

Commission Decision. The Commission finds that the current value of service pricing system for interruptible transportation service is not functioning as intended. The record reflects that value of service pricing was established to create an incentive for dual fuel customers to use natural gas at times when the relative prices of gas and oil would otherwise have tended to encourage those customers to use oil. Even when priced below the cost of fixed service, interruptible service for dual fuel customers benefited ratepayers by generating net distribution revenues that would have been foregone in the absence of the value of service pricing. Thus, value of service pricing maximized revenues for firm service customers by attracting net revenue from customers that would otherwise have used an alternative fuel. Ex. DIV-3 at 51-52 (Oliver).

In an environment where oil and gas prices are comparable, or the cost of natural gas exceeds the cost of oil on a per therm basis, value of service pricing for interruptible service

also makes sense because it can be said to recognize the quality of the service being provided to dual fuel customers. Fixed service customers are entitled to use the Company's distribution capacity at all times, to draw the volume of natural gas the customer calls for. Interruptible service customers may have their access to the distribution system suspended on short notice. Furthermore, in parts of Rhode Island, the service suspension can last most of the winter. When value of service pricing results in the cost of interruptible service being below the cost of firm service, that differential can also be rationalized by looking at the actual and potential service interruptions faced by non-firm customers.

Under the current tariff, $1.6 million of non-firm customer revenue is assumed in base rates. Non-firm revenues above $1.6 million are shared 75/25 between ratepayers and the Company. In recent years, the cost of oil has risen relative to the cost of natural gas. Value of service pricing has produced sizable marginal revenues for firm customers, as follows:

2005 – $1,200,000

2006 – $1,400,000

2007 – $1,700,000

2008 – $2,700,000

Ex. NGrid-36.

Rising oil prices, and the resulting increase in non-firm revenues, indicate that changes to the current value of service pricing are necessary and appropriate. Even the Company appears to agree that some change is necessary, as it has proposed capping the non-firm transportation tariff at 150% of the firm transportation rate. While the Company's approach has the potential benefit of limiting non-firm rate increases, while still extracting substantial non-firm revenues for the benefit of firm ratepayers, the Commission is not persuaded that this

modification of value of service pricing is sound ratemaking policy. Given the changes in energy markets and the economy since value of service pricing was introduced, it is time to move to a new approach.

The Company's proposal to cap value of service pricing at 150% of the firm rate was not supported by any financial or economic analysis, or even by any testimony explaining why the Company's proposed percentage cap is superior to a cap set at a higher or lower percentage. Accordingly, there is no evidence to suggest that the Company's proposal will maximize revenues from non-firm customers, which the Company asserts is the goal of value of service pricing.

The Commission also is not persuaded by the Company's arguments that a cost of service-based alternative pricing mechanism is too complex, and requires too many assumptions about non-firm costs and usage, to be workable. It is reasonable to assume that the Company has the expertise and experience with non-firm customers in Rhode Island to make educated calculations decisions regarding likely expenses and revenues. The Company presumably made those kinds of calculations and decisions before agreeing to include $1.6 million of non-firm revenues in base rates under the current tariff. Furthermore, the record reflects that the Company's New York affiliate offers non-firm service priced at 100% of the firm tariff rate. Tr. 10/08/08 at 112 (Czekanski). There is no reason to think that the Company could not implement a similar approach here in Rhode Island.

TEC-RI and Rhode Island Hospital argue that the Commission should order non-firm rates be set at a 40% discount off of firm rates. They assert that this level of discount will generate non-firm revenues in line with "historical" levels, and sufficient to cover the estimated non-firm costs of service reflected in the Company's cost of service study marked as an exhibit

during the hearings. Setting non-firm rates at a discount off of firm rates would, in their view, be a fair recognition of the fact that firm customers are assured of service year round, while non-firm customers can have their service interrupted, often for substantial periods. TEC-RI and Rhode Island Hospital also see setting non-firm rates at a fixed discount off of firm service as a way of reducing the recent volatility of non-firm pricing, which they assert makes it difficult for large Rhode Island employers to budget for energy costs.

The Commission agrees that price stability is generally desirable, and that setting the price of non-firm service as a fixed percentage of the price of firm service is a fair and reasonable methodology. For several reasons, however, the Commission does not agree that a 40% discount off of firm rates is appropriate. First, the cost of service studies submitted by the Company during the hearings were criticized by the Division. Therefore, the Commission finds that these studies, without more, are not a sufficient basis to set a non-firm discount off of firm pricing. Second, evidence presented at the hearings indicated that substantial numbers of non-firm customers have migrated to firm service in recent months. Pricing non-firm service at too deep a discount off of firm service may encourage not only the migration of these customers back to non-firm service, but additional switching by firm customers who find a 40% discount off of the cost of firm service economically attractive. This could have the undesirable effect for firm ratepayers of discouraging use of the distribution system. Third, while the Commission agrees that in some ways the quality of non-firm service is inferior to the quality of firm service – because service interruptions are allowed – the record reflects that non-firm customers can and do switch back and forth between alternative fuels to take advantage of price and demand changes. This ability to switch back and forth, without being committed to the natural gas distribution system in the same way as a firm customer, has a value to the non-firm customer that

offsets the disadvantage of potential service interruptions. For all of these reasons, the Commission adopts the Division's recommendation that non-firm service should be priced at a 20% discount off of firm pricing.

On November 5, 2008, the Company and the Division entered into a stipulation to address the potential revenue effects of the Commission's decision on this issue. NGrid Post-Hearing Mem. at 90; Division Post-Hearing Mem. at 37. The stipulation created a mechanism to account for the various possible migrations of customers between firm and non-firm service, depending on how rates for non-firm service are ultimately established, in order to assure revenue neutrality for customers and the Company. Going forward, non-firm distribution revenues will be determined by combining revenues (exclusive of gross earning tax) from the customers identified in the stipulation plus margins received from non-firm special contracts and new non-firm customers taking non-firm service after that date. For the period ending June 30, 2009, the Company will calculate the total non-firm transportation margins for the eight month period ending June 30. If the total non-firm margins are greater than $1,879,800 during that period, firm rate payers will receive credit for the excess through the DAC. If the total is less than $1,879,800, firm ratepayers will make up the difference through the DAC. For years ending June 30, 2010 and after, the break point for DAC credit will be $2,816,000. NGrid Post-Hearing Mem. at 90-92. The Commission approves the stipulation.

2. Sharing of Non-Firm Revenues.

Under the existing tariff, seventy-five percent of non-firm revenues above $1.6 million are credited to the ratepayers; the other 25% are retained by the Company. In the year ending June 30, 2008, firm customers received $2,884,688 over and above the $1.6 million built into the revenue requirement, for a total firm customer benefit of $4,484,688. Ex. PUC-7 (NGrid Response to Data Request COMM 3-9). The Company's 25% share for the same period

amounted to $961,563. Since 2003, the Company has retained a total of $2,628,300 of non-firm margin. *Id.*

Company Position. The Company proposed retaining the revenue split.

Division Position. The Division objected to retaining the revenue split. Ex. DIV-3 at 64 (Oliver). The Division argued that while value of service pricing was originally designed to encourage maximization of revenues from non-firm customers with access to competitively priced alternative fuels, that basis no longer exists after industry restructuring. Ex. DIV-3 at 51, 62-63 (Oliver). The Division argued that the Company's retention of this margin does not affect its pricing of non-firm service, or the behavior of non-firm customers. Division Post-Hearing Mem. at 38-39. The Division further argued that it is not reasonable for the Company to continue sharing the benefit of non-firm margins above $1.6 million, while ratepayers absorb all of the risk of returns below that level. *Id.* at 39.

Commission Decision. The Commission finds that in light of its decision to fix non-firm prices at a 20% discount off of firm prices, there is no longer any reason to offer the Company a share of non-firm revenues as an incentive to maximize those revenues. The Company's proposed revenue split is denied.

3. Lock In Period.

The Company proposed enlarging the time for non-firm transportation customers to lock in service prior to the beginning of a month from five to ten days. The Commission approves this proposed change.

4. Flexible Firm Service.

The Company proposed Flexible Firm Service, a firm transportation service based on negotiated, individual service agreements with dual-fuel C&I customers with usage above 150,000 therms. Ex. NGrid-15 at 21 (Czekanski). The Division opposed the proposal, citing a

lack of detail and the possible inequality of bargaining strength between the Company and a non-firm customer. Division Post-Hearing Mem. at 40; Ex. DIV-3 at 62 (Oliver). The Commission agrees that the proposed Flexible Firm Service lacks sufficient detail, and therefore declines to approve it at this time.

5. Non-Firm Sales Service Tariff.

The Company proposed eliminating non-firm sales service. Ex. NGrid-15 at 22 (Czekanski). TEC-RI proposed that the Company retain the non-firm sales tariff until the Company determines that no current customer under that tariff will be harmed if it is eliminated. TEC-RI Post-Hearing Mem. at 2. The Commission has not been presented with sufficient evidence to determine the full implications of eliminating non-firm sales service, as proposed. The Company's request to eliminate non-firm sales service is therefore denied.

G. Firm Service Rates

The Company proposed raising customer charges for residential customers from $9 to $16, and proposed increases for commercial and industrial customers (excluding Extra Large C&I) as well. The overall increase in distribution revenue requested by the Company is 15.95%. Proposed increases for certain classes range from 46.7% to over 114%. Division Post-Hearing Mem. at 43; Ex. DIV-3 at 45 (Oliver).

The Division objected to the proposed increases in customer charges, arguing that violate the ratemaking principles of gradualism, continuity and avoidance of rate shock. The Division proposes that no class should receive increases in customer and demand charges exceeding the greater of 33% or the class average increase. Tr. 8/27/08 at 182; Division Post-Hearing Mem. at 43.

The Commission finds that the proposed increases in customer and demand charges are excessive in comparison to the proposed increase in the Company's distribution

revenue requirement. The Commission approves the Division's recommendation that no class should receive increases in customer and demand charges exceeding the greater of 33% or the class average increase.[14]

H. Other Rate Design Issues

1. Consolidation of Gas Cost Rate Charges.

The Company proposed to reduce the number of Gas Cost Recovery rates from six to two. The Company asserts that this change will simplify the GCR calculations and associated monthly reporting of deferred gas cost account balances. NGrid Post-Hearing Brief at 58. The Division supports the Company's proposal, concluding that it would have no significant adverse impacts. Ex. DIV-3 at 73 (Oliver). TEC-RI opposes this change as a step away from cost of service pricing. TEC-RI believes that it could increase the GCR rates for certain classes by $0.10 /Dth or more, which translates into approximately $2.3 million. TEC-RI Post-Hearing Mem at 23-24.

The Commission finds that reducing the number of gas cost recovery rates will simplify the calculations and reporting and is in the best interest of ratepayers. The Commission approves the Company's proposed consolidation of six gas cost recovery rates to two rates.

2. DAC Adjustments

The Company proposed several changes to the Distribution Adjustment Clause to reflect other tariff changes requested by the Company in its filing. The Commission approves DAC cost recovery mechanisms consistent with its rulings set forth above for the Company's Accelerated Replacement Program and pension and PBOP expenses. The Commission also approves elimination of the Consolidation Mitigation and ERI adjustment. The other DAC

[14] Commissioner Bray dissents from this portion of the Commission's decision and opposes any increase in the fixed customer charge for reasons stated on the record at the November 24, 2008 Open Meeting. Tr. 11/24/08 at 99-101.

adjustments proposed by the Company are denied as moot in light of the Commission's rulings on decoupling and recovery of gas cost related bad debt. TEC-RI's request to modify the DAC mechanism to allocate DAC costs and credits to rate classes based on class revenues (as a proxy for cost of service allocation) instead of through a volumetric charge is denied.

3. Three Year Rate Plan Proposal.

The Company proposed an alternative three year rate plan. The plan would phase in rate increases approved in this proceeding. The Division opposed the Company's alternative three year plan, arguing that (1) it is less beneficial if the Company's revenue proposal is reduced as recommended by the Division, (2) it is difficult to forecast revenue requirements for the two years after the rate year with any degree of certainty, (3) incorporating Commission modifications to the Company's proposed revenue requirement over three years is complex, and (4) the proposed three year plan would generate approximately $23 million of revenues in excess of the revenues produced by the alternative request for a one time increase of $20 million. Division Post-Hearing Mem. at 34-35.

The Commission finds that the approved distribution revenue increase of approximately $13 million is less burdensome to ratepayers than the Company's initial $20 million request. The Commission further finds that the additional cost and complexity of phasing in the increased revenue requirement over three years outweighs the benefits of a phase in for ratepayers. The Commission declines to approve the Company's alternative three year rate plan.

Accordingly, it is

(19563) ORDERED:

Decoupling

1. Revenue Decoupling Mechanism. The Company's proposed revenue decoupling mechanism for the residential non-heating, residential heating, small C&I and medium C&I rate classes, under which the surplus above or shortfall below target revenue per customer would be credited or collected through an annual adjustment of the DAC, is denied;

Revenue Requirement Issues

2. Revenue Requirement. A rate year revenue requirement of $139,266,486 is approved, representing a $13,659,773 (10.88%) increase over the test year of $125,606,713.[15]

3. Capital Structure. The Company's proposed capital structure for ratemaking purposes of 47.71% equity, 40.63% long-term debt and 11.66% short-term debt is approved;

4. Return on Equity. The Company's proposed return on equity of 11.50% is denied. The Company shall be allowed a return on equity of 10.50% for its Rhode Island operations;

5. Size of Rate Base. The Company's proposed rate base of $285,241,458 is approved, provided that, in the event that the projected capital spending does not occur prior to the end of the rate year, the Company shall notify the Division and

[15] In response to the Commission's open meeting ruling on November 24, 2008, the Company submitted a Compliance Tariff Filing consistent with the approved revenue requirement. The Commission approved the filing on December 1, 2008. Order No. 19528 (issued January 8, 2009). A copy of Compliance Tariff Filing, Schedule NG-Compliance MDL-1, page 1 of 2 and Schedule NG-Compliance RD-1 is attached hereto as Appendix A.

make an appropriate adjustment to reflect the actual lower amount of actual plant in service;

Operating Expenses (Cost of Service)

6. Health Care Costs. The Company's proposed rate year medical and dental costs of $4,614,616 shall be reduced by $907,456, to $3,707,150;

7. FAS 112 Expense. The Company's proposed FAS 112 expense – relating to post-employment benefits other than pension – of $740,000 for FY 2009 is approved;

8. Synergy Savings – Southern Union Merger. The Company's proposed $1,054,609 synergy saving from the Company's August 2006 acquisition of the Rhode Island operations of New England Gas Company from Southern Union is denied;

9. Synergy Savings – KeySpan Merger. The stipulation between the Company and the Division relating to synergy savings resulting from the Company's August 2007 merger with KeySpan Corporation is approved. A base rate revenue credit of $2.45 million shall be included to reflect the ratepayers' 50% share of projected merger synergies net of costs to achieve. The Company shall be allowed to include its $2.45 million share of projected merger synergies in future rate cases, and to reflect its share of savings in annual earnings reports filed with the Commission for earnings sharing purposes, to the extent permitted by the stipulation. The Company's request for permission to create a regulatory asset in accordance with FAS 71 is approved;

10. Gas Marketing Program. The Company's proposal to include $1,377,000 in the base revenue requirement for a Gas Marketing Program is denied;

11. Uncollectible Expenses. The stipulation between the Company and the Division to reduce the Company's proposed uncollectible accounts receivable expense of $3,594,522 by $150,000 is approved;

12. Rate Case Expense. The Company's total rate case expenses of $1,348,443 (including Company expenses of $884,481, Division expenses of $113,075, and Commission expenses of $350,887) are approved. The Company shall be allowed to recover these expenses amortized over a three year period, or $449,481 per year;

13. Encroachment Expenses. The Company's proposed $1,054,000 for operation and maintenance expenses relating to public works and third party encroachment is denied. Encroachment expenses of $298,000 are approved;

14. Distribution Maintenance. The Company's proposed distribution maintenance expenses shall be reduced by $539,000, to $16,265,000;

Revenue Reconciliation Proposals

15. Accelerated Capital Replacement Program. The Company's proposed Accelerated Replacement Program to increase the annual replacement of distribution mains and remove high pressure inside services is approved, subject to the modifications recommended by the Division. Beginning in January 2009, the Company will submit a proposed implementation schedule to the Division each January for comment, and secure Commission approval. The Company will also submit a reconciliation report for each fiscal year. The first ARP reconciliation report for the 12 months ending March 31, 2009 will be submitted by May 15, 2009 for a rate adjustment effective July 1, 2009. The ARP will

entitle the Company to a rate adjustment only to the extent of the capital cost that is incremental to the amount included in base rates in this proceeding.

16. Gas-Supply Related Bad Debt Cost. The Company's proposed bad debt ratio of 2.46% for base rates is approved. The Company's proposed gas cost related bad debt reconciling mechanism is denied;

17. Reconciliation of Pension and PBOP. The Company's proposed annual reconciliation mechanism for pension and PBOP (post-retirement benefits other than pension) expenses is approved;

Low Income Discount

18. 10% Low Income Discount. The Company's proposed 10% discount of off Commission-approved customer and distribution charges for low income residential heating and non-heating customers eligible for LIHEAP assistance is approved. The discount shall be collected from other ratepayers based on consumption, as proposed by the Company;

Non-Firm Tariff Issues

19. Pricing for Non-Firm Transportation Customers. The Company's proposed cap on non-firm transportation rates at 150% of firm rates is denied. Non-firm transportation rates shall be set by the Company at a 20% discount off of firm customer rates. The Company's proposed sharing of non-firm revenues above $1.6 million is denied. The November 5, 2008 stipulation between the Company and the Division creating a mechanism to account for the various possible migrations of customers between firm and non-firm service is approved;

20. Lock In Period. The Company's proposal to enlarge the time for non-firm transportation customers to lock in service prior to the beginning of a month from five (5) to ten (10) days is approved;

21. Flexible Firm Service. The Company's proposal to establish a flexible firm transportation service is denied;

22. Non-Firm Sales Service. The Company's proposal to eliminate non-firm sales service is denied;

Firm Service Rates

23. Firm Service Base Charge. The Company's proposed increases in customer and demand charges shall be modified such that no class of ratepayers shall receive increases in customer and demand charges exceeding the greater of 33% or the class average increase;

Other Rate Design Issues

24. Consolidation of Gas Cost Recovery Rates. The Company's proposed consolidation of gas cost recovery rates from six rates to two rates is approved;

25. DAC Adjustments. The Company's proposed DAC cost recovery mechanisms for the Company's Accelerated Capital Replacement Program and pension and PBOP expense reconciliation are approved. The proposed elimination of the Consolidation Mitigation and ERI adjustment is approved. Other DAC adjustments proposed by the Company and TEC-RI are denied;

26. Three Year Rate Plan. The Company's proposed alternative three year rate plan is denied;

27. The Company is further ordered to comply with the reporting requirements and all other findings and directives contained in this Decision and Order.

EFFECTIVE AT WARWICK, RHODE ISLAND, PURSUANT TO AN OPEN MEETING DECISION OF THE COMMISSION ON NOVEMBER 24, 2008. WRITTEN ORDER ISSUED JANUARY 29, 2009.

PUBLIC UTILITIES COMMISSION

Elia Germani, Chairman

Robert Holbrook, Commissioner

Mary E. Bray, Commissioner

APPENDIX A

National Grid - RI Gas
Approved Revenue Requirement
Commission Open Meeting - November 24, 2008

			Decision Matrix Item
1	Co Rebuttal Position	$18,455,310	
2	Health care Adjust	(907,456)	5
3	FAS 112	740,000	6
4	SU Synergy Savings	(896,971)	7
5	SU CTA Amortization	(157,637)	7
6	Gas Marketing	(1,377,000)	9
7	Rate Case Expense (see page 2 of 2)	183,731	11
8	Low Income Uncollectible Adj	(150,000)	10
9	Pre-tax Return @ 10.50% ROE (5.01% - 5.49% * 286,031,702) /.65	(2,112,234)	2, 3 & 4
10	Rev Req Adjustment subtotal (sum of Lines 1 through 9)	(4,677,567)	
11	Bad Debt impact ((Line 10 / .9754) - Line 11)	(117,970)	
12	Total Revenue Requirement (Line 1 plus lines 10 & 11)	$13,659,773	

NationalGrid RI
Docket No.3943
Proposed Revenue Spread - Compliance

Line No.	Rate Schedule	Current Distribution Revenue	Proposed Increase	Proposed Distr. Rev. before LI Discount	Percentage Increase	Low Income Full Rate Reallocation	Low Income Discount Revenue $ 792,453	Total Proposed Distribution Revenue
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
1	Residential Non-Heat	$ 5,133,293	$ 781,903	$ 5,915,196	15.23%	$ (485,600)	$ 12,037	$ 5,441,633
2	Residential Non-Heat Discount	-	-	-	0.00%	485,600	(48,565)	437,035
3	Residential Heat	82,164,785	8,939,534	91,104,319	10.88%	(7,439,952)	379,512	84,043,878
4	Residential Heat Discount	-	-	-	0.00%	7,439,952	(743,888)	6,696,064
5	Small C/I	10,491,164	1,426,798	11,917,962	13.60%		54,238	11,972,200
6	Medium C/I	14,650,241	1,155,611	15,805,852	7.89%		120,912	15,926,764
7	Large Low	6,730,933	530,936	7,261,869	7.89%		60,898	7,322,767
8	Large High	1,812,681	172,370	1,985,051	9.51%		23,720	2,008,771
9	X-Large Low	1,108,782	156,826	1,265,608	14.14%		27,671	1,293,279
10	X-Large High	3,473,673	491,316	3,964,989	14.14%		113,465	4,078,454
11	NGV	22,738	2,474	25,212	10.88%			25,212
12	Gas Lights	18,423	2,004	20,427	10.88%			20,427
13	Total	$ 125,606,713	$ 13,659,773	$ 139,266,486	10.88%	$ -	$ 0	$ 139,266,486
14	Percent Increase		10.88%					

ATTACHMENT D

COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

AT RICHMOND, DECEMBER 23, 2008

2008 DEC 23 P 1:09

APPLICATION OF

VIRGINIA NATURAL GAS, INC.

CASE NO. PUE-2008-00060

For approval to implement a natural gas conservation and ratemaking efficiency plan including a decoupling mechanism and to record accounting entries associated with such mechanism

ORDER APPROVING NATURAL GAS
CONSERVATION AND RATEMAKING EFFICIENCY PLAN

On July 3, 2008, Virginia Natural Gas, Inc. ("VNG" or "Company"), filed with the State Corporation Commission ("Commission") an Application pursuant to the recently enacted Natural Gas Conservation and Ratemaking Efficiency Act ("Act"), § 56-600 *et seq.* of the Code of Virginia ("Code"), seeking approval to implement a natural gas conservation and ratemaking efficiency plan, which includes a decoupling mechanism, and to record accounting entries associated with such mechanism.

As set forth in the Application, the Company's proposed conservation and ratemaking efficiency plan has two principal components: (i) an Energy Conservation Plan ("ECP") to promote conservation and efficiency; and (ii) a Revenue Normalization Adjustment, Rider D ("RNA Rider" or "Rider"), which is a natural gas decoupling mechanism that provides for a sales adjustment to customers' monthly bills. The Application seeks: (1) approval of the ECP and RNA Rider effective January 1, 2009; (2) approval to capitalize the program costs (including capital costs) and to defer such costs pending the appropriate cost of service treatment, including recovery in rates, until the expiration of the Company's performance-based regulation plan

("PBR Plan") period;[1] and (3) authority to begin recording accounting entries associated with the RNA Rider decoupling mechanism effective January 1, 2009.

VNG states in the Application that its proposal does not result in a shift in the annualized allowed distribution revenue between any rate classes and maintains the non-gas revenue per customer within the rate classes established in the Company's PBR Plan. Over the initial three-year term, the Company proposes to spend $7.5 million in these programs (including the cost of capital). For that expenditure, the Company asserts that its customers can save $39.5 million over a 10-year period.[2]

The Company asserts that its proposed decoupling mechanism breaks the link between the volume of sales and the recovery of fixed costs and allows for an increased focus by local distribution companies on energy efficiency and conservation measures. Specifically, the RNA Rider is designed to separate revenues from throughput, enabling VNG to mitigate the impact of declining customer usage and to promote energy efficiency and conservation while recovering its fixed costs. According to VNG, widespread conservation would diminish gas demand and, if significant enough, could dampen natural gas commodity prices. For individual customers, the Application states that any lowering of commodity volumes consumed will result in cost avoidance.

As set forth in the Application, the Company's ECP proposal included the following energy conservation initiatives:

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[1] The Commission approved VNG's PBR Plan in 2006. *See Application of Virginia Natural Gas, Inc., For approval of a performance based rate regulation methodology pursuant to Virginia Code § 56-235.6*, and *General Rate Case Filing of Virginia Natural Gas, Inc., For investigation of justness and reasonableness of current rates, charges, and terms and conditions of service in compliance with prior Commission Order*, Case Nos. PUE-2005-00057 and PUE-2005-00062, 2006 SCC Ann. Rept. 341 (July 24, 2006) ("PBR and Rate Case Order").

[2] *See* Exh. 2 (Gidley direct) at 6.

- *Seasonal Check-Up Program*: $25 customer incentive for check-up or credit toward a programmable thermostat; recommended 21-point inspection and filter examination;

- *Low-Income Home Weatherization Program*: Individual home weatherization at no cost to qualified individuals; $1,650 per home; program to be administered in partnership with current providers of low-income weatherization programs;

- *Energy Efficient Tank Water Heater Program*: $250 incentive; installation of a tank-style natural gas water heater with an energy factor of 0.62 or greater;

- *Tankless Water Heater Program*: $500 incentive; installation of a tankless natural gas water heater with an energy factor of 0.82 or greater;

- *Space Heating Program*: $500 incentive; installation of a 90%+ Efficient Natural Gas Furnace;

- *Pilot ENERGY STAR® Residential New Construction Program*: Natural gas water heater and natural gas furnace incentives plus a $250 incentive to be applied against the cost of the ENERGY STAR® inspections, testing, and modeling; a pilot program to encourage the installation of highly energy efficient ENERGY STAR® rated equipment in residential new construction rather than the standard less-costly and less-efficient equipment;

- *Community Outreach and Customer Education Program*: A broad-based energy conservation education program specifically related to each of the above programs and directed at VNG's customers.[3]

The Company allocates the annual program costs among the above programs and requests "the ability to be flexible and transfer funds from one component to another if it determines that would be more effective or if participation in one of the components is greater than anticipated, ..."[4] The annual program costs also include "$8,000 for the administrative cost related to the processing of the incentive-related payments," and the Company proposes "to

[3] Exh. 5 (France direct), Attach. CJF-1.

[4] Exh. 6 (Hickerson direct) at 6.

defer the cost related to the annual independent verification of the net benefits . . . as required by the new legislation, and other incremental ECP costs[, which] are not expected to exceed $25,000."[5] Finally, the Application requests authority to capitalize the program costs (including capital costs) and to defer such costs pending the appropriate cost of service treatment, including recovery in rates, until the expiration of VNG's PBR Plan period on August 1, 2011, during which time the Company's base rates are frozen pursuant to the Commission's decision in Case Nos. PUE-2005-00057 and PUE-2005-00062.

On July 14, 2008, the Commission issued an Order for Notice and Hearing that, among other things, directed the Company to provide notice of its Application, established a procedural schedule for this case, and scheduled a public hearing to receive testimony from members of the public and evidence on the Application. The Commission subsequently extended the procedural schedule in response to a motion filed by the Office of the Attorney General's Division of Consumer Counsel ("Consumer Counsel"). The Commission received written comments from: the New Kent County Board of Supervisors (opposing a rate increase); the Natural Resources Defense Council ("NRDC") (supporting efforts to implement decoupling and energy efficiency programs); and the Virginia Interfaith Center for Public Policy ("Center") (supporting the Application).

On October 14, 2008, the Commission convened a public hearing for the purpose of receiving testimony from public witnesses, and the following testified as public witnesses thereat: Brandi Colander on behalf of NRDC; and Rev. C. Douglas Smith on behalf of the Center.

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[5] *Id.*

On October 22, 2008, VNG filed a Proposed Stipulation and Recommendation between VNG and Consumer Counsel.

On October 23, 2008, the Commission convened a public evidentiary at which the following participated and presented one or more witnesses: VNG; Consumer Counsel; and the Commission's Staff ("Staff").

On October 29, 2008, VNG filed a Proposed Stipulation and Recommendation (REVISED) ("Revised Stipulation") between VNG and Consumer Counsel, as had been discussed during the October 23 hearing. The Revised Stipulation includes the following modifications to the Company's proposed conservation and ratemaking efficiency plan:

1. The VNG Community Outreach and Customer Education Program will include, through VNG bill inserts and/or other media materials, energy efficiency and conservation educational information targeted to all VNG residential customers throughout each year of the [ECP]. The Company will also make available to every VNG residential customer a $4.00 coupon each year for replacement of an air filter through a supplier with whom VNG will partner (*e.g.*, Home Depot, Sears, *etc.*), with the expectation of attaining high customer participation. The total cost of all (ECP) programs will not change. Program costs for the air filter coupon will be included as part of the Community Outreach and Customer Education spending.

2. An Energy Conservation and Efficiency Advisory Group will be formed (the composition of which will be mutually agreed upon by VNG, the Commission and Consumer Counsel), which will meet periodically to evaluate, review, and recommend adjustments to VNG's conservation and energy efficiency programs (*i.e.*, ECP), including items such as, but not limited to: evaluating results, customer behavior and additional needs of the customers; reviewing program participation, public perception, attendance at outreach meetings, and participation on the Company's website; and recommending new conservation and efficiency technology and hotline telephone numbers to provide conservation advice, new and revised conservation education programs, forums, potential partnerships that should be explored for increased outreach, and change in media/messaging based on review of results.

3. The Company will also implement a programmable thermostat program in which the Company will partner with a supplier to make thermostats available to a group of customers at wholesale prices by taking advantage of bulk purchasing. The Company will provide $25 per customer towards the purchase of these thermostats. The Company will spend $125,000 on this program. The total cost of all (ECP) programs will not change. Program costs will be reallocated as shown on Exhibit A [to the Revised Stipulation]. In addition, as described in the seasonal check up program included in VNG's Application, customers would still be eligible to receive $25 toward the purchase of a programmable thermostat if they choose to purchase a model other than what the Company provides under the program described in this paragraph of the Stipulation.

4. In compliance with the Va. Code § 56-602, VNG will, on an annual basis, file an annual report with Commission Staff showing the year-over-year weather-normalized use of natural gas on an average customer basis for the Residential Customer Class and an independently-verified report of the economic benefits created by the conservation and energy efficiency programs (*i.e.*, ECP). Such report will include the findings and recommendations of the Energy Conservation and Efficiency Advisory Group, including cost benefit analysis of the conservation and energy efficiency programs (*i.e.*, ECP), participation rates, an effectiveness test comparing results to a non-participating control group, and expected program benefits for the next program year.

5. The [plan] shall be limited to an initial period of not more than 3 years from the effective date approved by the Commission. If VNG desires to continue the [plan] after the 3-year period, it will be required to seek further authority to do so from the Commission.

6. Nothing herein shall prevent the Energy Conservation and Efficiency Advisory Group from proposing mutually agreeable changes to the ECP within the 3-year period.

7. The Company shall not earn a return or recover any form of carrying costs on deferred incremental costs incurred within the 3-year period for its conservation and energy efficiency programs. The undersigned parties agree that the Company's proposal as modified herein complies with the definition "Cost-effective conservation and energy efficiency program" for purposes of recovery of deferred incremental costs pursuant to Va. Code

> § 56-602.D. The ECP costs, excluding carrying costs, shall be included in VNG's next rate proceeding as an expense for recovery over an amortized period. The deferred ECP costs will not be classified as rate base in VNG's next rate proceeding.[6]

On November 26, 2008, VNG, Consumer Counsel, and Staff filed post-hearing briefs.

NOW THE COMMISSION, having considered this matter, is of the opinion and finds that a conservation ratemaking and efficiency plan as permitted by § 56-600 *et seq.* of the Code is approved as set forth in this Final Order. We approve the Revised Stipulation entered into by VNG and Consumer Counsel and, consistent with the Revised Stipulation, we (1) direct a reallocation of the program costs among the ECP programs to ensure compliance with the Act, and (2) do not increase the *total* cost to the Company of all ECP programs.

This is the first case under the Act. We find that the conservation ratemaking and efficiency plan, as defined by the provisions of the Revised Stipulation and the requirements of this Final Order ("Plan"), satisfies the statutory requirements of the Act.

Code of Virginia

Section 56-602 A of the Code provides in part as follows:

> Notwithstanding any provision of law to the contrary, each natural gas utility shall have the option to file a conservation and ratemaking efficiency plan as provided in this chapter. Such a plan may include one or more residential, small commercial, or small general service classes, but shall not apply to large commercial or large industrial classes of customers. Such plan shall include: (i) a normalization component that removes the effect of weather from the determination of conservation and energy efficiency results; (ii) a decoupling mechanism; (iii) one or more cost-effective conservation and energy efficiency programs; (iv) provisions to address the needs of low-income or low-usage residential customers; and (v) provisions to ensure that the rates and service to non-participating classes of customers are not adversely impacted. Such plan may also include provisions for phased or targeted

[6] Exh. 3 (Revised Stipulation) at 1-4.

implementation of rate or tariff design changes, if any, or conservation and energy efficiency programs.

Section 56-602 B of the Code directs in part as follows:

> The Commission shall approve or deny, within 180 days, a natural gas utility's initial application for any revenue-neutral conservation and ratemaking efficiency plan that allocates annual per-customer fixed costs on an intra-class basis in reliance upon a revenue study or class cost of service study supporting the rates in effect at the time the plan is filed. A plan filed pursuant to this subsection shall not require the filing of rate case schedules. . . . The Commission shall approve such a plan . . . if it finds that the plan's . . . proposed decoupling mechanism is revenue-neutral and is otherwise consistent with this chapter.

Section 56-600 of the Code includes definitions of some of the terms used above, including the following:

> '*Allowed distribution revenue*' means the average annual, weather-normalized, nongas commodity revenue per customer associated with the rates in effect as adopted in the applicable utility's last Commission-approved rate case or performance-based regulation plan, multiplied by the average number of customers served.
>
> '*Conservation and ratemaking efficiency plan*' means a plan filed by a natural gas utility pursuant to this chapter that includes a decoupling mechanism.
>
> '*Cost-effective conservation and energy efficiency program*' means a program approved by the Commission that is designed to decrease the average customer's annual, weather-normalized consumption or total gas bill, for gas and nongas elements combined, or avoid energy costs or consumption the customer may otherwise have incurred, and is determined by the Commission to be cost-effective after analyzing such program using the Total Resource Cost Test, the Societal Test, the Program Administrator Test, the Participant Test, the Rate Impact Measure Test, and any other test the Commission reasonably deems appropriate. The Commission may determine the weight to be given to a test. Without limitation, rate designs or rate mechanisms, customer education, customer incentives, and weatherization programs are examples of conservation and energy efficiency programs that the Commission may consider.

> '*Decoupling mechanism*' means a rate, tariff design or mechanism that decouples the recovery of a utility's allowed distribution revenue from the level of consumption of natural gas by its customers, including (i) a mechanism that adjusts actual nongas distribution revenues per customer to allowed distribution revenues per customer, such as a sales adjustment clause, (ii) rate design changes that substantially align the percentage of fixed charge revenue recovery with the percentage of the utility's fixed costs, such as straight fixed variable rates, provided such mechanism includes a substantial demand component based on a customer's peak usage, or (iii) a combination of clauses (i) and (ii) that substantially decreases the relative amount of nongas distribution revenue affected by changes in per customer consumption of gas. . . .
>
> '*Revenue-neutral*' means a change in a rate, tariff design or mechanism as a component of a conservation and ratemaking efficiency plan that does not shift annualized allowed distribution revenue between customer classes, and does not increase or decrease the utility's average, weather-normalized nongas utility revenue per customer for any given rate class by more than 0.25 percent when compared to (i) the rate, tariff design or mechanism in effect at the time a conservation and ratemaking efficiency plan is filed pursuant to this chapter or (ii) the allocation of costs approved by the Commission in a rate case using the cost of service methodology set forth in § 56-235.2 or a performance-based regulation plan authorized by § 56-235.6, where a plan is filed in conjunction with such case.

Section 56-602 E of the Code mandates as follows:

> The Commission shall require every natural gas utility operating under a conservation and ratemaking efficiency plan approved pursuant to this chapter to file annual reports showing the year over year weather-normalized use of natural gas on an average customer basis, by customer class, as well as the incremental, independently verified net economic benefits created by the utility's cost-effective conservation and energy-efficiency programs during the previous year.

Conservation and Ratemaking Efficiency Plan

Both parts of the Plan - *i.e.*, the ECP and the RNA Rider - apply only to VNG's residential customers served under Rate Schedule 1 (Residential Firm Gas Sales Service) and

Rate Schedule 3 (Residential Air Conditioning Firm Gas Sales Service).[7] Accordingly, the Plan complies with the requirement in § 56-602 A of the Code that "[s]uch a plan may include one or more residential, small commercial, or small general service classes, but shall not apply to large commercial or large industrial classes of customers."

Conservation and energy efficiency programs

As noted above, the first principal component of the Plan is the ECP, which contains the Company's proposed conservation and energy efficiency programs.

Normalization component

As required by § 56-602 A (i) of the Code, the Plan includes "a normalization component that removes the effect of weather from the determination of conservation and energy efficiency results." VNG explains as follows:

> The Company will . . . compute the weatherized usage and revenue that will be used in the determination of the conservation and energy efficiency results. In addition, we will track, on an individual premise basis, the consumption and revenue for each premise that participates in any component of the ECP (the Company's initiatives to encourage conservation and efficiency). The usage and revenue associated with each of these premises will be weather normalized to allow for the effectiveness of the respective plans to be evaluated on a component-by-component basis.[8]

Low-income or low-usage residential customers

As required by § 56-602 A (iv) of the Code, the Plan includes "provisions to address the needs of low-income or low-usage residential customers." The Plan, as proposed and approved herein, includes a Low-Income Home Weatherization Program that, among other things: (1) will be administered in partnership with current providers of low-income weatherization programs;

[7] *See, e.g.*, Exh. 6 (Hickerson direct), Attach. ARH-1 at 1.

[8] Exh. 6 (Hickerson direct) at 14-15.

(2) will provide individual home weatherization at no cost to qualified individuals at a value of up to $1,646 per home; (3) will have a total program cost of $372,075; and (4) will serve at least 226 low-income households.[9]

Cost-effective conservation and energy efficiency programs

Section 56-602 A (iii) of the Code states that the Plan "shall include . . . one or more *cost-effective* conservation and energy efficiency programs" (emphasis added). As noted above, the Act includes a definition for a "cost-effective conservation and energy efficiency program."[10] That definition, among other things, requires the Commission to determine whether such program is cost-effective after analyzing the program using several named tests "and any other test the Commission reasonably deems appropriate."[11] In addition, the Act does not require that a program pass any or all of the tests and, further, provides that "[t]he Commission may determine the weight to be given to a test."[12]

In this regard, the ECP passes all the named tests except the Rate Impact Measure Test ("RIM Test").[13] The RIM Test generally measures the rate impact on residential customers that do not participate in the ECP and, thus, is sometimes referred to as the "Non-Participant Test."[14] Staff explained that, under VNG's own analysis included in its Application, approximately 96% of residential customers will be *negatively* impacted by the ECP in any given year - *i.e.*, 96%

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[9] *See, e.g.,* Exh. 5 (France direct) at 8-9; Exh. 20 (France rebuttal) at 4-5; Exh. 3 (Revised Stipulation), Exhibit A.

[10] Va. Code § 56-600.

[11] *Id.*

[12] *Id.*

[13] *See, e.g.,* VNG's November 26, 2008 post-hearing brief at 35-37; Staff's November 26, 2008 post-hearing brief at 6-8, 14-15; Consumer Counsel's November 26, 2008 post-hearing brief at 3-5.

[14] *See, e.g.,* Exh. 8 (Watkins direct) at 5-6; Exh. 14 (Walker direct) at 8.

could pay higher bills than they otherwise would have absent the ECP.[15] Indeed, Consumer Counsel explains that the ECP requires "non-participating [residential] ratepayers to pay for the monetary benefits received only by the program's participants. . . ."[16]

This disparity, however, highlights one of the ratemaking premises reflected in the Act: customers in a rate class who do not conserve (*i.e.*, assumed non-participants) may pay more in order for the Company to recoup the revenue lost from those who conserved. This policy, built into the statute, will necessarily make it difficult for many conservation programs to meet the RIM Test. Consumer Counsel explains this by noting that, under the Act, there will be "disparate impact" between participants and non-participants in a rate class, and that the Commission should determine whether such impact "is reasonable or not."[17] Thus, Consumer Counsel "*cautions* the Commission against applying the RIM Test in a manner that could result in adopting a policy that *no* conservation and energy efficiency programs as envisioned by the Act would *ever* be approved."[18]

The Act also permits the Commission to analyze the ECP using "any other test the Commission reasonably deems appropriate."[19] The results of the RIM Test highlight the limited number of residential customers that are expected to take part in the ECP as proposed in the

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[15] *See* Exh. 14 (Walker direct) at 9.

[16] Exh. 8 (Watkins direct) at 7.

[17] Consumer Counsel's November 26, 2008 post-hearing brief at 6.

[18] *Id.* (emphasis added). Although passage of the RIM Test is not a statutory prerequisite for approval, VNG (1) agrees that the Commission should not ignore the rate impact on non-participants, which VNG estimates at less than $0.72 per month, and (2) notes that the Act specifically permits "targeted" implementation of such programs. VNG's November 26, 2008 post-hearing brief at 35-36.

[19] Va. Code § 56-600.

Application. Thus, we find that it is reasonably appropriate to consider the number of customers targeted, and the type of programs that they are targeted with, as part of the ECP.[20] In this regard, we conclude as follows: (1) that for the Plan to be cost effective under the Act, the annual funds proposed by the Company should be allocated in a manner that appreciably increases the realistically possible number of participants in significant conservation measures; and (2) that this shall be accomplished by increasing the allocation of funds for the Programmable Thermostat Program resulting in a total allocation as set forth below. This reallocation of funds should, among other things, help to reduce the potential number of non-participants that will be required to pay for this Plan, but that gain no benefit thereunder.

Accordingly, the ECP shall reflect the following allocation:

Community Outreach and Customer Education Program
Annual Cost: $750,000
Incentive: --
Number of Participants: --

Programmable Thermostat Program
Annual Cost: $625,000
Incentive: $25
Number of Participants: 25,000

Low-Income Home Weatherization Program
Annual Cost: $372,075
Incentive: $1,646
Number of Participants: 226

Seasonal Check-Up Program
Annual Cost: $188,750
Incentive: $25
Number of Participants: 7,550

[20] We recognize that the Revised Stipulation, which includes a $4.00 air filter coupon (to be paid out of the funds allocated to the Community Outreach and Customer Education Program) and a Programmable Thermostat Program for 5,000 customers, should increase participation in the ECP. *See* Exh. 3 (Revised Stipulation).

Tank Water Heater Program
Annual Cost: $26,500
Incentive: $150
Number of Participants: 177

Tankless Water Heater Program
Annual Cost: $98,000
Incentive: $500
Number of Participants: 196

Space Heating Program
Annual Cost: $98,000
Incentive: $500
Number of Participants: 196

ENERGY STAR® Residential New Construction Program
Annual Cost: $5,000
Incentive: $250
Number of Participants: 20

This reallocation does not exceed the *total* cost of the ECP programs contained in the Revised Stipulation and is consistent with the Revised Stipulation. We find that, at this time, the above allocation is necessary to make the ECP "cost-effective" under the Act and to address the potential deficiencies in the Plan identified by the RIM Test. We recognize, as did VNG, that it may be reasonable to transfer funds from one program to another after gaining actual experience with the ECP, without increasing the total cost of all programs.[21] Furthermore, the Revised Stipulation provides that the Energy Conservation and Efficiency Advisory Group (created as part of the Revised Stipulation) will evaluate and recommend changes to the ECP programs during the three-year term of the Plan. Accordingly, while we direct the cost allocations set forth above at this time, we do not preclude modifications thereto after the first year of the Plan. Thus, in accordance with the Revised Stipulation, the reallocation directed herein may be reviewed by the Energy Conservation and Efficiency Advisory Group, and requests for any further

[21] *See* Exh. 6 (Hickerson direct) at 6.

reallocations of ECP program costs during the life of the Plan may be made to this Commission by that group.

Decoupling mechanism

As noted above, the second principal component of the Plan is the RNA Rider, which represents the Company's proposed decoupling mechanism under § 56-602 A (ii) of the Code. We find that the RNA Rider, which is a sales adjustment clause, complies with the specific provisions of the Act and, as required by § 56-602 B of the Code, is otherwise consistent with the provisions of the Act.

Sales adjustment clause

Staff opposed the form of the Rider, preferring that such a Rider, if any, be in the form of a change in rate design and not a sales adjustment clause.[22] This position, however, is contrary to the explicit language of the statute permitting the decoupling mechanism to take the form of a sales adjustment clause. Specifically, as permitted by the Act, the Rider is a "mechanism that decouples the recovery of a utility's allowed distribution revenue from the level of consumption of natural gas by its customers, including (i) a mechanism that adjusts actual nongas distribution revenues per customer to allowed distribution revenues per customer, such as a *sales adjustment clause*."[23]

Customer classes

As required by § 56-602 A (v) of the Code, the Plan includes "provisions to ensure that the rates and service to non-participating classes of customers are not adversely impacted." The Act describes "classes of customers" in terms of "residential, small commercial, . . . small

[22] *See, e.g.*, Tr. 233-234.

[23] Va. Code § 56-600 (emphasis added).

general service classes, [and] large commercial or large industrial classes of customers."[24] The Plan only applies to the residential class of customers, and the rates and service to "non-participating classes of customers" - *i.e.*, small commercial, small general service, large commercial, and large industrial classes - are not impacted, adversely or otherwise, by the Plan.[25]

In this regard, we reject Staff's proposition that customer classes - under the express terms of the Act - could mean something other than the residential, small commercial, small general service, large commercial, and large industrial customer classes.[26] Rather, we agree with Consumer Counsel's explanation as follows:

> The statute speaks in terms of the residential, small commercial, small general service, large commercial, and large industrial classes of customers. The entire residential class of customers - Schedules 1 and 3 - is included under VNG's proposed [Plan]. The small commercial and small general service classes are legally eligible to be included in a [Plan], but under VNG's proposed plan those classes are not included. Thus, in this instance, Consumer Counsel understands subdivision (v) to require that rates and service under VNG's [Plan] applicable to the residential class of customers not adversely impact the small commercial or small general service classes of customers, as well as the large commercial and large industrial classes of customers.[27]

Thus, contrary to Staff's suggestion, which diverges from the plain language of the Act, the Act does not permit the Commission to create subsets of classes within the residential class as identified by statute.

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[24] Va. Code § 56-602 A.

[25] *See, e.g.*, Exh. 6 (Hickerson direct) at 18.

[26] *See, e.g.*, Tr. 275-279.

[27] Consumer Counsel's November 26, 2008 post-hearing brief at 7.

Revenue-neutral

Similarly, as required by the Act's definition of "revenue-neutral," the RNA Rider "does not shift annualized allowed distribution revenue between *customer classes*."[28] No revenue is shifted between customer classes; the ECP and the Rider only apply to the residential class of customers.

Next, as also required by the Act's definition of "revenue-neutral," the RNA Rider "does not increase or decrease the utility's average, weather-normalized nongas utility revenue per customer for any given rate class by more than 0.25 percent when compared to (i) the rate, tariff design or mechanism in effect at the time a conservation and ratemaking efficiency plan is filed pursuant to this chapter."[29] As noted by VNG, the "rates in effect at the time VNG filed its Plan were adopted by the Commission in the Company's PBR Plan Proceeding."[30] Under the PBR Plan, VNG's average, weather-normalized nongas utility revenue per customer for the residential class is $223.68, and the RNA Rider is designed to ensure that such revenue per customer remains at $223.68.[31]

Staff asserts, nonetheless, that the Rider is not revenue-neutral. The RNA Rider, as required by the Act, is based on the PBR Plan that, in turn, is based on usage for the 12 months ending March 2005.[32] Staff explains that usage during that 12-month period was higher than any

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[28] Va. Code § 56-600 (emphasis added).

[29] Va. Code § 56-600. Contrary to Staff' suggestion, subsection (ii) of the definition of "revenue-neutral" in § 56-600 of the Code is inapplicable herein, because the Plan was not "filed in conjunction with" a rate case or PBR plan.

[30] VNG's November 26, 2008 post-hearing brief at 9.

[31] *See, e.g.*, Exh. 16 (Hickerson rebuttal) at 3-4; VNG's November 26, 2008 post-hearing brief at 11-12.

[32] *See, e.g.*, Exh. 14 (Walker direct) at 15.

subsequent 12-month period.[33] For example, Staff illustrates that if the RNA Rider was in effect during 2006 and 2007 - without the ECP program - VNG's revenues would have increased by over 5%; that is, customers would have paid over 5% more than they actually paid during 2006 and 2007 if the RNA Rider was in effect.[34] We must reject Staff's conclusion as a matter of law. The Act explicitly defines "revenue-neutral" as applied above, and Staff's analysis does not comply with such definition.

Efficiency targets and penalties for poor performance

VNG states that the Natural Resources Defense Council ("NRDC") "has filed comments in this proceeding supporting the Company's decoupling and conservation plan. . . ."[35] The NRDC, however, testified at the hearing that it is not familiar with the specific conservation programs proposed by VNG in its Application.[36] The NRDC also asserts that in conjunction with the benefits received by the Company through the decoupling mechanism, the Plan also should include energy "efficiency targets" for VNG and should reflect "penalties for poor performance" by VNG under the ECP.[37] Staff similarly suggests that the decoupling mechanism be linked to the amount of conservation achieved under the ECP.[38] The Company, however, asserts that "[d]ecoupling revenue should not be directly tied to conservation,"[39] and

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[33] *Id.*

[34] *See* Exh. 14 (Walker direct) at 15-16.

[35] VNG's November 26, 2008 post-hearing brief at 41.

[36] Tr. 13-14.

[37] *See, e.g.,* Tr. 10-12; NRDC's October 8, 2008 comments at 3.

[38] *See, e.g.,* Exh. 12 (Spinner direct) at 20-21; Exh. 14 (Walker direct) at 20-21.

[39] *See* VNG's November 26, 2008 post-hearing brief at 21 (typeface modified).

"[decoupling revenue to VNG] is not a reward for conservation. . . ."[40] In this regard, the Company is correct that the Act does not require the linkage recommended by the NRDC and Staff. Although the NRDC asserts that such efficiency targets and penalties for poor performance should be part of any successful decoupling program, the Act includes no provision for such penalties and does not tie the definition of "decoupling mechanism" to any amount of conservation. Accordingly, we must deny the NRDC's and Staff's recommendations in this regard.

Bills

Staff states that: (1) the RNA Rider represents VNG's "third adjustment to the bills of its residential customers;" (2) the two current adjustments are to reflect (a) normal weather (*i.e.*, a weather normalization adjustment ("WNA")), and (b) purchased gas costs; and (3) the "layering of rate adjustments can give rise to billing errors and increased customer confusion."[41]

In this regard, we note that the RNA Rider adjustment (i) is a monthly adjustment, and (ii) can represent either a credit or a surcharge to the customer's bill. Similarly, the WNA (i) is a monthly adjustment, and (ii) can represent either a credit or a surcharge to the customer's bill. Further, the Commission requires VNG to list the impact of the WNA as a separate line item on the customer's monthly bill; this provides a reasonable level of billing transparency and assists in identifying the individual bill impact of the WNA program. We likewise find that VNG shall list the impact of the RNA Rider adjustment as a separate line item on the customer's monthly bill. As with the WNA, we find that the risk of confusion from a separate line item is outweighed by the value to customers of billing transparency.

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[40] *Id.* at 22.

[41] Exh. 14 (Walker direct) at 26.

Reports

As required by § 56-602 E of the Code, VNG will file annual reports "'showing the year over year weather-normalized use of natural gas on an average customer basis, by customer class, as well as the incremental, independently verified net economic benefits created by the utility's cost-effective conservation and energy-efficiency programs during the previous year.'"[42] We further note that the Plan, as approved herein, includes the following provision:

> In compliance with the Va. Code § 56-602, VNG will, on an annual basis, file an annual report with Commission Staff showing the year-over-year weather-normalized use of natural gas on an average customer basis for the Residential Customer Class and an independently-verified report of the economic benefits created by the conservation and energy efficiency programs (*i.e.*, ECP). Such report will include the findings and recommendations of the Energy Conservation and Efficiency Advisory Group, including cost benefit analysis of the conservation and energy efficiency programs (*i.e.*, ECP), participation rates, an effectiveness test comparing results to a non-participating control group, and expected program benefits for the next program year.[43]

PBR Plan

Consumer Counsel and Staff note the potential conflict between the Plan and VNG's existing PBR Plan as approved by the Commission.[44] The Company, however, correctly points out that the Act explicitly permits VNG to implement a conservation and ratemaking efficiency plan regardless of whether the Company is operating under a Commission-approved PBR Plan.[45] Section 56-601 B of the Code provides as follows: "Natural gas utilities are authorized pursuant to this chapter to file natural gas conservation and ratemaking efficiency plans that implement

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[42] *See, e.g.,* VNG's November 26, 2008 post-hearing brief at 39-40.

[43] Exh. 3 (Revised Stipulation) at 3-4.

[44] *See, e.g.,* Exh. 8 (Watkins direct) at 15-16; Exh. 14 (Walker direct) at 16.

[45] *See* VNG's November 26, 2008 post-hearing brief at 8-9.

alternative natural gas utility rate designs and other mechanisms, in addition to . . . performance-based regulation plans authorized by § 56-235.6." Moreover, as noted above, § 56-602 A of the Act further states as follows: "Notwithstanding any provision of law to the contrary, each natural gas utility shall have the option to file a conservation and ratemaking efficiency plan as provided in this chapter." Accordingly, we find that VNG's existing PBR Plan does not stand as a legal impediment to implementation of the Plan herein.

At the same time, we must also acknowledge that the Plan will necessarily change the amount that VNG's customers otherwise would have paid for non-gas service under the PBR Plan as approved by the Commission.[46] In the PBR and Rate Case Order, the Commission found that VNG's annual revenues needed to be *reduced* by approximately $9.83 million in order for rates to be considered "just and reasonable."[47] The Commission, however, did not order a rate decrease but, rather, approved the existing PBR Plan that, among other things: (1) requires VNG to construct a pipeline from its northern system that will cross the James River/Hampton Roads Channel and tie into VNG's distribution system in Norfolk to allow for the physical flow of gas

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[46] For example, while the Commission does not currently intend to re-open the PBR Plan for further evaluation, we recognize that the PBR statute directs that the Commission may "alter, amend or revoke" a previously approved PBR Plan if it finds, among other things, that:

> (iv) the performance-based form of regulation is resulting in rates that are excessive compared to a gas utility's or electric utility's cost of service and any benefits that accrue from the performance-based plan; (v) the terms ordered by the Commission in connection with approval of a gas utility's or electric utility's implementation of a performance-based form of regulation have been violated; or (vi) the performance-based form of regulation is no longer in the public interest.

Va. Code § 56-235.6 C.

[47] *See* PBR and Rate Case Order, 2006 SCC Ann. Rept. at 347.

from the northern system to the southern system ("HRX Pipeline"); and (2) freezes VNG's non-gas rates for five years (August 1, 2006, to July 31, 2011).[48]

The Commission approved the rates in the PBR Plan[49] because we found that those rates complied with the specific requirements of the PBR statute; to wit, we found that the PBR Plan did "not result in excessive rates" under § 56-235.6 B of the Code "when compared to the benefits" to customers under the PBR Plan, which included the Company's commitment to construct the HRX Pipeline (a commitment that VNG has kept)[50] and the projected long-term cost savings to customers over the life of the HRX Pipeline.[51] Thus, having found that VNG's annual non-gas revenues should be reduced by $9.83 million, allowing non-gas rates to remain unchanged through the five-year PBR Plan period was a necessary and obviously critical component of our approval of that plan.

Indeed, in seeking approval of the PBR Plan, the Company repeatedly assured the Commission that VNG's customers would be assured of "rate certainty" for the non-gas portion of service for the five-year life of the PBR Plan.[52] The Commission relied upon such representations in approving the PBR Plan and, further, explained that rates would be reduced by

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[48] *Id.*

[49] Commissioner Jagdmann did not participate in the PBR and Rate Case Order.

[50] *See, e.g.*, VNG's November 12, 2008 Report of Action in Case No. PUE-2005-00057.

[51] *See* PBR and Rate Case Order, 2006 SCC Ann. Rept. at 349.

[52] *See, e.g.*, the following statements from VNG in Case No. PUE-2005-00057: "The PBR Plan freezes VNG's [non-gas] rates at their 1996 level until 2011. This provides continued stable rates [over the five-year PBR period] - a guarantee of 14 years of stable base rates . . ." (Application at 9); "[The five-year rate freeze] provide[s] *rate certainty* for our customers for at least five years" (January 27, 2006 Statement of VNG President Henry P. Lingenfelter at 6 (emphasis added)); "[A]ll parties to the [PBR] case have agreed to the current rates for a five-year period" (VNG's January 30, 2006 Reply at 6); and "[The five-year rate freeze] provid[es] *rate certainty* to all VNG customers for at least five years" (VNG's January 30, 2006 Reply at 4 (emphasis added)).

$9.83 million if the PBR Plan was ever withdrawn or terminated.[53] That reliance, however, apparently was misplaced since, upon implementation of the Plan, the price paid by many - if not all - residential customers for non-gas service may likely increase.

First, as discussed above, the Plan is structured so that the Company is guaranteed to recover the average, weather-normalized non-gas utility revenue per customer that is reflected in the PBR Plan. While we conclude that the RNA Rider is "revenue-neutral" as that term is defined by the Act, the Rider is by no means "revenue-neutral" in terms of its likely actual effect on individual customers. The Plan is structured so that VNG is guaranteed to recover a certain amount of revenue from the residential class, regardless of how much natural gas the class uses as a whole. This is accomplished, through the Rider, by effectively increasing rates to all members of the residential class, via a "sales adjustment" when sales volumes decline, in order to meet VNG's guaranteed revenue for that class.[54] As a result, all customers - whether or not they decrease their individual natural gas usage - end up paying more to VNG for the non-gas portion of their bills.

The Company acknowledges that, under its Plan, the bill increases to individual customers are not directly tied to any particular conservation targets or savings, such as, *e.g.*, when VNG states that "decoupling revenue [to VNG] should not be directly tied to conservation"[55] savings to customers, and "[decoupling revenue to VNG] is not a reward for

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[53] *See* PBR and Rate Case Order, 2006 SCC Ann. Rept. at 349 ("If the PBR Plan is withdrawn or terminated, and absent a subsequent rate case or performance based ratemaking methodology, VNG's rates shall be established in accordance with the revenue requirements and rate design found just and reasonable by the Commission under § 56-235.2 A of the Code in Case No. PUE-2005-00062.").

[54] Conversely, VNG asserts that customers would receive a credit under the RNA Rider if the revenue per customer exceeds that reflected in the PBR Plan. *See* Exh. 16 (Hickerson rebuttal) at 12.

[55] VNG's November 26, 2008 post-hearing brief at 21.

conservation . . . ."[56] Moreover, when VNG states that the Act "allows cost shifting on an intra-class basis,"[57] it recognizes that individual VNG residential ratepayers may pay more than they are currently paying under the PBR Plan rate structure, even if they reduce their consumption of natural gas or already use relatively little gas.

Second, and as also explained above, the RNA Rider is based on the usage and revenue reflected by the PBR Plan. This PBR Plan revenue is based on historical customer usage for the 12 months ending March 2005, and Staff explains that "there has been no single consecutive 12-month period when actual usage conditions were higher than the [RNA Rider] targets since March 2005."[58] For example, in 2006 and 2007 the average usage was less than that for the 12 months ending March 2005. As a result, if the RNA Rider was in effect during 2006 and 2007, residential customers would have seen a "sales adjustment" under the Rider in order to increase VNG's revenues. In other words, if the RNA Rider was in effect during 2006 and 2007, residential customers' bills would have been *higher* than they actually were in 2006 and 2007 under the PBR Plan - and this is without any ECP programs.[59] Thus, the implementation of the RNA Rider clearly may increase residential customers' bills from what they otherwise would have been under the PBR Plan.

VNG asserts, however, that this result from the Rider is not technically a *rate increase* but, rather, represents a *sales adjustment* as permitted by the Act. VNG claims that a "sales adjustment clause" - such as the RNA Rider - which increases a customer's bill pursuant to the Act is not the same thing as a rate increase because the "sales adjustment clause allows [VNG] to

[56] *Id.* at 22.

[57] *Id.*

[58] Exh. 14 (Walker direct) at 15.

[59] *See, e.g.*, Exh. 14 (Walker direct) at 15; Exh. 8 (Watkins direct) at 17-19.

obtain its 'allowed distribution revenue' without changing its rates."[60] While we find that VNG is technically correct in its legal interpretation of a "sales adjustment clause" under the Act, we also recognize that this technical ratemaking distinction is likely of little comfort to ratepayers. If a customer's bill goes up, calling it a *sales adjustment* – as opposed to a *rate increase* – does not change the fact that the customer's bill is higher than it otherwise would have been.[61] As a result, we must acknowledge that while customers' "rates" technically may not change as a matter of legal analysis under the Act, the actual effect of VNG's sales adjustment clause (*i.e.*, the RNA Rider) may be increases in many customers' bills versus what they would have been under the PBR Plan, which we approved in 2006 with the expectation that we were ensuring "rate certainty" as represented by VNG.

Accordingly, while we approve the Plan herein pursuant to the Act, we must acknowledge that the ultimate price that VNG's residential customers will pay for non-gas service under the Plan may be higher than the frozen rates established by the Commission in the PBR Plan. This is especially relevant at a time of economic hardship when many of VNG's customers are struggling to pay their monthly bills and may be facing tremendous uncertainty about their employment security.[62]

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[60] VNG's November 26, 2008 post-hearing brief at 17 (quoting Va. Code § 56-600). *See also id.* at 9-13.

[61] In other words, it is possible that a particular customer's bill could be higher for an equivalent amount of natural gas consumed. This higher cost per unit of consumption would typically be considered a rate increase.

[62] As recently reported in the Wall Street Journal: "One in five U.S. households was behind on its utility bills coming out of last winter, a new survey concludes, raising fears that the current heating season could be even worse. One in 20 households had its utility service terminated in 2007." Rebecca Smith, *One in Five Households Fell Behind on Utility Bills Last Winter*, WALL STREET JOURNAL, December 17, 2008, at A6 (discussing a survey by the National Association of Regulatory Utility Commissioners).

Projected Savings from the Plan

VNG's customers who participate in the conservation measures proposed in the Plan can save money on the volumetric portion of their bills through reduced consumption. Quantifying total net savings for customers with accuracy is difficult, however. In this regard, we find VNG's claim that its customers, over a 10-year period, can save as much as $39.5 million from the Plan as proposed to be speculative.[63] While the *costs* to customers of the ECP will be definite, and price increases for non-gas service under the RNA Rider are probable, as explained above, attempting to quantify net *savings* from the Plan is an exercise dependent upon a myriad of changing factors, including the *future* behavior of customers and the *future* price of natural gas.

We note that on the date that VNG filed this Application (July 3, 2008), the price of natural gas at Henry Hub was $13.31 per MMBtu; by December 1, 2008, the price had plunged to $6.43,[64] a drop of *more than 50%* in just a few months. Whether prices will remain this low, go even lower, or skyrocket in the future is unknowable. In addition, while some of the recent drop in natural gas prices may be attributable to the worldwide decline in demand for all energy commodities because of the global economic crisis, there may also be reason to speculate that the natural gas markets in the United States are seeing the effects of substantial increases in domestic sources of supply, for example, from the Barnett field in Texas. There is also reportedly huge potential from the Marcellus Shale field in the Appalachian Basin.[65] The quantity of savings to customers on the volumetric portion of their bills from reduced consumption obviously moves in

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[63] *See* Exh. 2 (Gidley direct) at 6 ("For that level of expenditure [$7.5 million for the conservation programs, including the cost of capital], our customers can save up to $39.5 million over a 10-year period. *That is a permanent, sustainable savings that provides significant value to our customers*" (emphasis added).).

[64] *See, e.g.*, ICE Day Ahead Natural Gas Price Report published by ICE Data (https://www.theice.com/marketdata/reportcenter/reports.htm).

[65] This potential "super giant" gas field extends from far southwest Virginia through West Virginia, Ohio, Pennsylvania, and New York. *See, e.g.*, http://geology.com/articles/marcellus-shale.shtml.

concert with gas prices. There are, of course, other factors, such as finite pipeline capacity or the possibility of continued dollar devaluation in the future, that could put upward pressure on prices and increase savings from reduced consumption.

Accordingly, IT IS HEREBY ORDERED THAT:

(1) A three-year conservation ratemaking and efficiency plan, as permitted by § 56-600 *et seq.* of the Code of Virginia, is approved as set forth in this Order Approving Natural Gas Conservation and Ratemaking Efficiency Plan and shall become effective on January 1, 2009.

(2) The Revised Stipulation is approved as set forth herein.

(3) The ECP program costs shall be allocated as set forth herein.

(4) This matter is dismissed.

Commissioner Morrison participated in this matter.

Commissioner Dimitri did not participate in this matter.

AN ATTESTED COPY hereof shall be sent by the Clerk of the Commission to: Edward L. Flippen, Esquire, Kristian M. Dahl, Esquire, and Bernard L. McNamee, Esquire, McGuireWoods LLP, One James Center, 901 East Cary Street, Richmond, Virginia 23219-4030; C. Meade Browder, Jr., Senior Assistant Attorney General, Office of the Attorney General, Division of Consumer Counsel, 900 East Main Street, Second Floor, Richmond, Virginia 23219; and the Commission's Office of General Counsel and Divisions of Energy Regulation, Public Utility Accounting, and Economics and Finance.

filed electronically in docket office on 10/29/09

IN THE TENNESSEE REGULATORY AUTHORITY
AT NASHVILLE, TENNESSEE

IN RE:	)	
	)	
Petition of Piedmont Natural Gas Company, Inc. for Approval of Service Schedule No. 317 and Related Energy Efficiency Programs	)	**DOCKET NO. 09-00104**

RESPONSES AND OBJECTIONS OF THE CONSUMER ADVOCATE TO PIEDMONT'S DISCOVERY REQUEST

Robert E. Cooper, Jr., Attorney General and Reporter for the State of Tennessee, by and through the Consumer Advocate and Protection Division of the Office of the Attorney General ("Consumer Advocate"), pursuant to the Hearing Officer's ruling at the status conference held on June 4, 2008, hereby submits its responses and objections to the first discovery request of Piedmont Natural Gas Company, Inc. ("Piedmont" or "Company").

GENERAL OBJECTIONS

1. The Consumer Advocate objects to the definitions and instructions contained in the Company's interrogatories to the extent that the definitions and instructions attempt to impose on the Consumer Advocate a burden or obligation greater than that required by the *Tennessee Rules of Civil Procedure* and applicable statutes and regulations governing contested case hearings.

2. The Consumer Advocate objects to the interrogatories to the extent they call for information and the production of documents which are protected from disclosure by the attorney-client privilege, the attorney work product doctrine or any other applicable privilege or protection. The Consumer Advocate objects to the data requests to the extent that the Company is attempting to impose on the Consumer Advocate obligations with regard to identification of

privileged documents beyond those required by the *Tennessee Rules of Civil Procedure* and applicable statutes and regulations governing contested case hearings.

3. The Consumer Advocate objects to the Company's interrogatories to the extent they seek information not related to the subject matter involved in this litigation or to the extent they are not reasonably calculated to lead to the discovery of admissible evidence. By providing information in response to these requests, the Consumer Advocate does not concede that such information is relevant, material or admissible in evidence. The Consumer Advocate reserves all rights to object to the use of such information as evidence.

4. The Consumer Advocate objects to the Company's interrogatories to the extent that the Company is attempting to impose on the Consumer Advocate obligations to supplement its responses beyond those required by the *Tennessee Rules of Civil Procedure* and applicable statutes and regulations governing contested case hearings.

5. The Consumer Advocate objects to the Company's interrogatories to the extent that the Company is attempting to require the Consumer Advocate to provide information and produce documents beyond those in its possession, custody or control as that phrase is used in the *Tennessee Rules of Civil Procedure* and applicable statutes and regulations governing contested case hearings.

6. The Consumer Advocate objects to the Company's data requests to the extent they seek information and documents that are readily available through public sources or are in the Company's own possession, custody or control. It is unduly burdensome and oppressive to require the Consumer Advocate to respond or produce documents that are equally available to the Company.

7. The Consumer Advocate's objections and responses to these requests are based on information now known to it. The Consumer Advocate reserves the right to amend, modify or supplement its objections and responses if it learns of new information.

8. The Consumer Advocate's responses to these requests are made without waiving or intending to waive the right to object to the use of any information provided in response to any

subsequent proceeding or trial of this or any other action. The Consumer Advocate's responses to these requests are also not a waiver of any of the foregoing objections or any objections it has made or may make with respect to any similar, related, or future data request, and the Consumer Advocate specifically reserves the right to interpose any objection to further requests notwithstanding any response or lack of objection made in this response.

9. The Consumer Advocate will supplement its responses in accordance with the requirements of state law.

10. The Consumer Advocate expressly incorporates these general objections into its responses set forth below.

Subject to and without waiving any objections stated above the Consumer Advocate responds to the specific requests as follows:

DISCOVERY RESPONSES AND OBJECTIONS

1. State the Consumer Advocate's position on what is the most appropriate mechanism or financial incentive to ensure that Piedmont's financial incentives are aligned with the state's energy conservation policy as set out in 2009 Public Act 531, Section 53.

RESPONSE:

Consistent with the General Objections above, the Consumer Advocate objects to the extent this request seeks privileged information or information protected from disclosure by attorney work product doctrine or other applicable law. The Consumer Advocate's work on this issue is on-going; consequently, it reserves the right to supplement and produce additional information as it becomes available. The Consumer Advocate's analysis in this case is fact intensive and detail oriented. The Consumer Advocate's analysis and opinion(s) are dependent upon information which is in the hands of Piedmont and which has not yet been made available to the Consumer Advocate.

Subject to and without waiving these objections and in an effort to avoid delaying this proceeding the Consumer Advocate responds as follows:

See the *Statement of the Consumer Advocate on Implementing Conservation Measures in Tennessee* filed in Docket 09-00065 on September 25, 2009. Moreover, the subject-matter of this docket, namely the implementation of the General Assembly's new energy conservation policy enumerated in 2009 Public Act 531, Section 53, is controlled by the following:

> The general assembly declares that the policy of this state is that the Tennessee regulatory authority will seek to implement, in appropriate proceedings for each electric and gas utility, with respect to which the authority has rate making authority, a general policy that ensures that utility financial incentives are aligned with helping their customers use energy more efficiently and that provides timely cost recovery and a timely earnings opportunity for utilities associated with cost-effective measurable and verifiable efficiency savings, in a way that sustains or enhances utility customers' incentives to use energy more efficiently.

The new policy neither requires nor forbids decoupling mechanisms to promote conservation. The natural gas industry, collectively, has submitted that the new policy should be implemented on a case by case basis, taking into account the differing operating conditions of the utilities and differing needs of customers and that the Authority should avoid a "one size fits all" policy. *See* the individual comments of Chattanooga Gas Company, Atmos Energy Corporation and Piedmont in Docket 09-00065 filed August 3-4, 2009. Thus, the appropriate mechanism, according to the state's natural gas industry, is a factually intensive and detail oriented subject-matter and dependent upon the circumstances of the individual utility. At this time, the Consumer Advocate's position is reliant upon Piedmont's company specific information and information showing both the short and long term financial impact of the Piedmont's proposal, which is currently not within the record or within the Consumer Advocate's possession.

The Consumer Advocate's position on this issue is to seek a policy which will encourage consumer energy conservation while allowing the utility to continue to have the opportunity to earn a fair return. Piedmont's proposal is a decoupling mechanism which the Company submits fulfills the State's policy. However, given the lack of specific information in the record, the Consumer Advocate is not satisfied at this time Piedmont's proposal is the appropriate policy tool to implement the State's new energy conservation policy.

Proponents of decoupling mechanisms have generally linked the concept of decoupling to energy conservation to the extent gas utilities promote decoupling mechanisms and conservation as one in the same. Decoupling has been described as a way to break the link between sales volume and utility revenues in order to allow a utility to encourage conservation. The theory sounds logical and laudable. However, the practical application of decoupling, as sought by the natural gas industry, has been subject to dispute and controversy. For example, the Iowa Utilities Board conducted an in-depth study of decoupling and rejected the proposal in 2006. Ultimately, the Board concluded the mandatory conservation programs specifically required under Iowa law for over a decade had no impact on the revenues of the utilities, thus decoupling was not needed. A copy of the order is attached at Tab A. In another example, the New Mexico Public Regulation Commission adopted the conclusions of the Hearing Officer rejecting a proposed decoupling mechanism that was characterized as designed to provide a "financial windfall" for utilities rather than making them financially neutral to conservation programs. An excerpt of the Hearing Examiner's order is attached at Tab B.[1]

In Rhode Island, decoupling has been rejected for natural gas consumers. The Commission noted that the financial benefits to the utility from decoupling were well

[1] Complete copies of the Hearing Examiners Ruling and the New Mexico Commission Order adopting the ruling is attached to Mike Chrslyer's Direct Testimony in Docket 07-00105, filed August 22, 2007 and publicly available through the TRA's electronic website.

documented in the record with information showing the utility would have collected an additional $34 million over the preceding four years had the mechanism been in place. However, any benefit accrued by consumers from decoupling would be based on speculation. A copy of the Commission's order is attached at Tab C. *See* pp. 57-72 for discussion and ruling.

In the context of shifting business risk to consumers, North Carolina is an example of a state in which a decoupling mechanism produced large rate increases while insulating Piedmont from economic risk. In 2005, the North Carolina Utilities Commission allowed Piedmont to implement a decoupling mechanism, known as the Customer Utilization Tracker ("CUT"), on an experimental basis. According to a report written by the North Carolina Utilities Commission and submitted to the Joint Legislative Utility Review Committee of the state legislature on October 2, 2008, the CUT produced $99.2 million dollars in additional rates owed to Piedmont by consumers in a three year period. Roughly half of this amount was attributable to price elasticity rather than the effects of the utility conservation program. The remaining half of the CUT's revenues was attributable to weather as the WNA in North Carolina was discontinued when the CUT was adopted. A copy of the report is attached to the Consumer Advocate's *Addendum to the Memorandum in Support of Motion Requesting Permission to Issue More Than Forty Discovery Requests*, filed in this docket on October 13, 2009.

The North Carolina Utilities Commission report states that warmer than usual weather and the effects of Hurricane Katrina and Hurricane Rita on natural gas prices contributed to financial impact of the CUT. The Consumer Advocate would note the impact of weather, natural gas prices and of the aforementioned hurricanes were equally felt in Tennessee. However, at no point during the three year period covered by the North Carolina report did Piedmont file a rate case in Tennessee.

Another example that is notable is in neighboring Virginia. In December of 2008, the Virginia State Corporation Commission ("Virginia Commission") implemented a decoupling mechanism pursuant to a 2008 law, the Natural Gas Conservation and Rate-making Efficiency Act ("Act"), requiring decoupling. Pursuant to the Act, Virginia Natural Gas, Inc. ("VNG") filed a proposed decoupling mechanism which the Virginia Commission approved. The final order issued by the Virginia Commission discusses the concerns and opposition of the Commission's staff regarding the decoupling mechanism, known as the Revenue Normalization Adjustment ("RNA"). A copy of the order is attached at Tab D. The pre-filed testimony of the Virginia Commission Staff which contains their findings is attached at Tab E. The Virginia Commission noted on page 18 of the order that had the RNA been in effect in 2006 and 2007, consumers would have paid more than 5% in additional rates in 2006 and 2007. However, the Act prevented the Commission from considering these concerns. The Authority is this matter has no similar legal constraint.

The decoupling debate has been on-going in Tennessee before the Authority. A decoupling mechanism proposed by Atmos Energy Corporation, which shares the basic framework of Piedmont's proposal, was rejected by the Authority as it removes any incentive for a utility to control fixed costs. Docket 05-00258, *Transcript of Proceedings*, October 26, 2006, pp. 6-7, 13 (*See* also Director Miller's Motion which is attached to the referenced transcript). In addition, Piedmont's decoupling proposal does not account for the additional revenue created by customer growth. The pre-filed written testimony on behalf of the Consumer Advocate concerning the off-setting effect to margin loss per customer, and even to an extent allowing over-earning in revenues and return on equity, from revenue generated from customer growth is publicly available online at the TRA website. See the pre-filed Direct Testimony of Mike

Chrysler in Docket 07-00105 filed on August 22, 2007; See also Rebuttal Testimony of Daniel McCormac in Docket 05-00258 filed on August 18, 2006. Recently, Atmos has acknowledged historical customer growth rates have offset the declining revenue per customer due to conservation while noting that customer growth had declined recently due to the downturn in the economy. *See* the sworn pre-filed Direct Testimony of Mr. Kevin Akers on behalf of Atmos Energy in Docket 08-00197 filed October 15, 2008. On page 4 at lines 1-2, Mr. Akers states historic growth rates have been "sufficient to overcome declining customer usage due to energy conservation and more efficient homes and appliances."

The decoupling debate is not confined to Tennessee or a few other states. See the attached presentation given by Ken Costello, senior economist for the National Regulatory Research Institute at Tab F. Mr. Costello's presentation provides an overview of the national debate on decoupling and examines the arguments both for and against decoupling. Other states have adopted modified decoupling mechanisms or adopted alternatives to decoupling in order to encourage conservation. The Colorado Public Utilities Commission modified a decoupling mechanism in order for both consumers and the utility to share risk and to encourage the utility to control costs. The order is attached at Tab G. *See* pages 11-13. New Jersey has adopted a modified mechanism. The order is attached at Tab H.

2. With respect to the position stated in response to the foregoing data request:

(a) Identify each and every factual basis relied upon by the Consumer Advocate in reaching such position;

RESPONSE:

Consistent with the General Objections above, the Consumer Advocate objects to the extent this request seeks privileged information or information protected from disclosure by attorney work product doctrine or other applicable law. Without waiving the aforementioned

objections, the Consumer Advocate responds as follows: See Response to Request 1. The Consumer Advocate reserves the right to produce more information as it becomes available to it.

(b) Identify each and every legal basis relied upon by the Consumer Advocate in reaching such position;

RESPONSE:

Consistent with the General Objections above, the Consumer Advocate objects to the extent this request seeks privileged information or information protected from disclosure by attorney work product doctrine or other applicable law. Without waiving the aforementioned objections, see Response to Request 1.

(c) Identify each and every witness the Consumer Advocate intends to call to support such position; and

RESPONSE:

The Consumer Advocate, consistent with the General Objections above, the Consumer Advocate objects to the extent that no decision has been made as to what witness will testify on any particular issue in this matter. Without waiving any objection, the Consumer Advocate responds as follows: At this time, it is possible Terry Buckner may provide testimony in support of a modified decoupling mechanism or in support of an alternative proposal. Mr. Buckner's opinion will be based on an analysis of information that is not currently within the possession of the Consumer Advocate, but rather in possession of the Company. The Consumer Advocate has requested this information from Piedmont. In addition, the Consumer Advocate has engaged consultants; however no decision has been made to whether such consultants will be engaged to provide testimony in this docket.

(d) Identify each and every document relating to, or reviewed or relied upon in reaching, such position.

RESPONSE:

Consistent with the General Objections above, the Consumer Advocate objects to the extent this request seeks privileged information or information protected from disclosure by attorney work product doctrine or other applicable law. The Consumer Advocate also objects to this Request as it is currently worded as being unduly broad and burdensome and beyond the scope of reasonably allowable discovery. It is unduly burdensome, unnecessary for the preparation of this Docket and practically unworkable for the Consumer Advocate to be required to produce every document in its possession that relates to the any position it might take in this Docket or that was reviewed by any consultant or other witness it may call in the Hearing on this Docket. The Consumer Advocate will produce for Piedmont all documents relied upon by any witness in formulating any opinion to be expressed by that witness in this Docket as soon as any such witness is finally selected by the Consumer Advocate and their opinions fully formed and decided. The Consumer Advocate is well aware of the compressed time frame that was requested by Piedmont in this Docket and will do its best to finalize the witnesses it intends to call and supplement this response with the required documents as quickly as possible and as far ahead of the deadline for filing Direct Testimony as possible. The Consumer Advocate's ability to finalize its plans for presenting any witnesses in this Docket is at least partially dependent upon receiving the information it seeks from Piedmont in Discovery. The earlier that the requested information is produced for the Consumer Advocate, the earlier that the Consumer Advocate can supplement its response to this request.

Without waiving the aforementioned objections, the Consumer Advocate responds as follows: See Response to Request 1. The Consumer Advocate reserves the right to produce more information as it becomes available to it.

3. If the Consumer Advocate's position is that an alternative mechanism may be more appropriate to fulfill the state's energy conservation policy as set out in 2009 Public Act 531, Section 53, identify the alternative mechanism(s) under the Consumer's Advocate's consideration.

RESPONSE:

See Response and objections to Request 1.

4. With respect to the position and any identified alternative mechanism stated in response to the foregoing data request:

(a) Identify each and every factual basis relied upon by the Consumer Advocate in reaching such position;

RESPONSE:

See Response and objections to Request 1 and 2(a).

(b) Identify each and every legal basis relied upon by the Consumer Advocate in reaching such position;

RESPONSE:

See Response and objections to Request 1 and Request 2(b).

(c) Identify each and every witness the Consumer Advocate intends to call to support such position; and

RESPONSE:

See Response and objections to Request 1 and Request 2(c).

(d) Identify each and every document relating to, or reviewed or relied upon in reaching, such position.

RESPONSE:

See Response and objections to Request 1 and Request 2(d).

5. State the Consumer Advocate's position on what is the most appropriate customer usage level and/or margin to be used as the benchmark for Piedmont's proposed decoupling mechanism.

RESPONSE:

A more recent benchmark for current customer usage and/or margin should be employed if the Authority determines Piedmont's decoupling proposal is the most appropriate mechanism pursuant to 2009 Public Act 531, Section 53. A more recent benchmark should more accurately reflect current economic conditions for the customer and the utility. Moreover, any future gains through energy conservation may be measured and/or accounted for in a more accurate fashion through use of a recent benchmark or one that is known and measurable in the future. However, the Consumer Advocate is awaiting information it has requested from the Company in order to conduct a full analysis. Any benchmark set for an approved decoupling mechanism will determine the immediate rate impact on consumers. At present, there has been no disclosure of the financial impact of Piedmont's proposal through the use of the Company's proposed benchmark.

In December of 2008, the Virginia State Corporation Commission ("Virginia Commission") implemented a decoupling mechanism proposed in Virginia pursuant to a 2008 law, the Natural Gas Conservation and Rate-making Efficiency Act ("Act"), mandating decoupling. Pursuant to the Act, Virginia Natural Gas, Inc. ("VNG") filed a proposed decoupling mechanism which the Virginia Commission approved. The Act required a benchmark from a utility's most recent rate case. The final order issued by the Virginia Commission fully discusses the concerns and opposition of the Commission's staff regarding the decoupling mechanism, known as the Revenue Normalization Adjustment ("RNA"), which used

a 2005 benchmark based on VNG's most recent rate case. The Virginia Commission Staff provided pre-filed testimony of the effect of the RNA on VNG's revenues and increase in the earned return on equity. A copy is attached at Tab D. The Virginia Commission noted on page 18 of the order that had the RNA been in effect in 2006 and 2007, consumers would have paid more than 5% in additional rates in 2006 and 2007. A copy of the order is attached at Tab E. The specific requirements of the Act prevented the Virginia Commission from taking any action to modify the final result of the RNA.

In addition, applying a usage benchmark which is several years old may be unreasonable given the timing of the implementation and results of the conservation programs. The consumer funded effort of the Company to encourage energy conservation is the justification for the proposed decoupling mechanism. However, if conservation programs are not implemented soon thereafter or are simply ineffective, there is no logical support for a usage benchmark based on 2003 data in order to raise rates in 2010. Consumers should not be expected to immediately and retroactively pay Piedmont for margin per customer lost at a 2003 level in 2010 when the promised benefit of utility sponsored conservation is not timely implemented or effective. For example, Piedmont's conservation programs in North Carolina were not fully implemented for almost two years after the decoupling mechanism went into effect. See Comments of Nashville Gas Company, filed in Docket 06-00309, August 8, 2007 at p. 7.

6. With respect to the position stated in response to the foregoing data request:

(a) Identify each and every factual basis relied upon by the Consumer Advocate in reaching such position;

RESPONSE:

Consistent with the General Objections above, the Consumer Advocate objects to the extent this request seeks privileged information or information protected from disclosure by

attorney work product doctrine or other applicable law. Without waiving the aforementioned objections, the Consumer Advocate responds as follows: See Response to Request 5. The Consumer Advocate reserves the right to produce more information as it becomes available to it.

(b) Identify each and every legal basis relied upon by the Consumer Advocate in reaching such position;

RESPONSE:

Consistent with the General Objections above, the Consumer Advocate objects to the extent this request seeks privileged information or information protected from disclosure by attorney work product doctrine or other applicable law. Without waiving the aforementioned objections, see Response to Request 5.

(c) Identify each and every witness the Consumer Advocate intends to call to support such position; and

RESPONSE:

The Consumer Advocate Consistent with the General Objections above, the Consumer Advocate objects to the extent that no decision has been made as to what witness will testify on what issue in this matter. Without waiving any objection, the Consumer Advocate responds as follows: At this time, it is possible Terry Buckner will provide testimony either agreeing with Piedmont's proposed benchmark or proposing an alternative. Any opinion put forth by Mr. Buckner will be based on an analysis of information that is not currently within the possession of the Consumer Advocate, but rather in possession of the Company. The Consumer Advocate has requested this information from Piedmont. In addition, the Consumer Advocate has engaged consultants; however no decision has been made to whether such consultants will be engaged to provide testimony in this docket.

(d) Identify each and every document relating to, or reviewed or relied upon in reaching, such position.

RESPONSE:

Consistent with the General Objections above, the Consumer Advocate objects to the extent this request seeks privileged information or information protected from disclosure by attorney work product doctrine or other applicable law. The Consumer Advocate also objects to this Request as it is currently worded as being unduly broad and burdensome and beyond the scope of reasonably allowable discovery. It is unduly burdensome, unnecessary for the preparation of this Docket and practically unworkable for the Consumer Advocate to be required to produce every document in its possession that relates to the any position it might take in this Docket or that was reviewed by any consultant or other witness it may call in the Hearing on this Docket. The Consumer Advocate will produce for Piedmont all documents relied upon by any witness in formulating any opinion to be expressed by that witness in this Docket as soon as any such witness is finally selected by the Consumer Advocate and their opinions fully formed and decided. The Consumer Advocate is well aware of the compressed time frame that was requested by Piedmont in this Docket and will do its best to finalize the witnesses it intends to call and supplement this response with the required documents as quickly as possible and as far ahead of the deadline for filing Direct Testimony as possible. The Consumer Advocate's ability to finalize its plans for presenting any witnesses in this Docket is at least partially dependent upon receiving the information it seeks from Piedmont in Discovery. The earlier that the requested information is produced for the Consumer Advocate, the earlier that the Consumer Advocate can supplement its response to this request.

Without waiving the aforementioned objections, the Consumer Advocate responds as follows: See Response to Request 5. The Consumer Advocate reserves the right to produce more information as it becomes available to it.

7. State the Consumer Advocate's position on the issue whether Piedmont's earnings should be evaluated prior to the implementation of a decoupling mechanism.

RESPONSE:

Piedmont has not had a rate case since 2003. It is incumbent upon the Authority to examine this issue, prior to making a determination as to the appropriate mechanism to carry out 2009 Public Act 531, Section 53. Moreover, the TRA must still determine whether this is an appropriate proceeding under 2009 Public Act 531, Section 53. Under Tennessee law, rates are required to be just and reasonable. The decoupling proposal of Piedmont effectively ends the concept of "regulatory lag" in traditional rate-making for residential consumers, the rates of which are already adjusted for weather, the cost of natural gas and uncollectible accounts.

Moreover, an examination of utility earnings in the context of decoupling is essential. The Iowa Utilities Board conducted an in-depth study of decoupling and rejected the proposal in 2006. Ultimately, the Board concluded the mandatory conservation programs specifically required under Iowa law for over a decade had no impact on the revenues of the utilities, thus decoupling was not needed. A copy of the order is attached with those documents addressing Response to Request 1.

In the context of the revenue produced by decoupling, such mechanisms have been shown to increase utility earnings. In December of 2008, the Virginia State Corporation Commission ("Virginia Commission") implemented a decoupling mechanism proposed in Virginia pursuant to a 2008 law, the Natural Gas Conservation and Rate-making Efficiency Act

("Act"), requiring decoupling. Pursuant to the Act, Virginia Natural Gas, Inc. ("VNG") filed a proposed decoupling mechanism which the Virginia Commission approved. The final order issued by the Virginia Commission fully discusses the concerns and opposition of the Commission's staff regarding the decoupling mechanism, known as the Revenue Normalization Adjustment ("RNA"). Testimony filed by the Virginia Commission Staff noted on page 18 of the order that had the RNA been in effect in 2006 and 2007, consumers would have paid more than 5% in additional rates in 2006 and 2007 while VNG's return on equity earned, rather than authorized, would increase. A copy of the Virginia Commission Staff pre-filed testimony is attached at Tab E.

8. With respect to the position stated in response to the foregoing data request:

(a) Identify each and every factual basis relied upon by the Consumer Advocate in reaching such position;

RESPONSE:

Consistent with the General Objections above, the Consumer Advocate objects to the extent this request seeks privileged information or information protected from disclosure by attorney work product doctrine or other applicable law. Without waiving the aforementioned objections, the Consumer Advocate responds as follows: See Response to Request 1, Request 6(c) and 7. The Consumer Advocate reserves the right to produce more information as it becomes available to it.

(b) Identify each and every legal basis relied upon by the Consumer Advocate in reaching such position;

RESPONSE:

Consistent with the General Objections above, the Consumer Advocate objects to the extent this request seeks privileged information or information protected from disclosure by

attorney work product doctrine or other applicable law. Without waiving the aforementioned objections, see Response to Request 7.

(c) Identify each and every witness the Consumer Advocate intends to call to support such position; and

RESPONSE:

The Consumer Advocate Consistent with the General Objections above, the Consumer Advocate objects to the extent that no decision has been made as to what witness will testify on any particular issue in this matter. Without waiving any objection, the Consumer Advocate responds as follows: At this time, it is possible Terry Buckner may provide testimony regarding this issue. Any opinion offered put forth by the Consumer Advocate will be based on an analysis of information that is not currently within the possession of the Consumer Advocate, but rather in possession of the Company. The Consumer Advocate has requested this information from Piedmont. In addition, the Consumer Advocate has engaged consultants; however no decision has been made to whether such consultants will be engaged to provide testimony in this docket.

(d) Identify each and every document relating to, or reviewed or relied upon in reaching, such position.

RESPONSE:

Consistent with the General Objections above, the Consumer Advocate objects to the extent this request seeks privileged information or information protected from disclosure by attorney work product doctrine or other applicable law. The Consumer Advocate also objects to this Request as it is currently worded as being unduly broad and burdensome and beyond the scope of reasonably allowable discovery. It is unduly burdensome, unnecessary for the preparation of this Docket and practically unworkable for the Consumer Advocate to be required to produce every document in its possession that relates to the any position it might take in this Docket or that was reviewed by any consultant or other witness it may call in the Hearing on this

Docket. The Consumer Advocate will produce for Piedmont all documents relied upon by any witness in formulating any opinion to be expressed by that witness in this Docket as soon as any such witness is finally selected by the Consumer Advocate and their opinions fully formed and decided. The Consumer Advocate is well aware of the compressed time frame that was requested by Piedmont in this Docket and will do its best to finalize the witnesses it intends to call and supplement this response with the required documents as quickly as possible and as far ahead of the deadline for filing Direct Testimony as possible. The Consumer Advocate's ability to finalize its plans for presenting any witnesses in this Docket is at least partially dependent upon receiving the information it seeks from Piedmont in Discovery. The earlier that the requested information is produced for the Consumer Advocate, the earlier that the Consumer Advocate can supplement its response to this request.

Without waiving the aforementioned objections, See Response to Request 7.

9. State the Consumer Advocate's position on whether the implementation of a decoupling mechanism lowers the business risk for Piedmont, thereby justifying an adjustment to its rate of return.

RESPONSE:

The Consumer Advocate submits that if consumers use less natural gas for any reason, Piedmont's proposed decoupling mechanism will allow the Company to raise the bills of consumers. Thus, the mechanism has the effect of guaranteeing revenues from residential consumers and shielding Piedmont from declining revenue for any economic or business reason. This has the effect of shifting business risk from the utility to consumers. This principle has been recognized in other states in terms of decoupling. This principle has been recognized and quantified by an expert testifying on behalf of Chattanooga Gas Company. *See* Pre-filed Direct Testimony of Dr. Roger A. Morin filed in TRA Docket 06-00175 on June 30, 2006.

In Connecticut, decoupling was rejected. In doing so, the Department of Public Utility Control stated that approval of a decoupling mechanism would require at least a 100 basis point reduction to the ROE to provide the commensurate risk compensation to consumers. A copy of the order is attached at Tab I. *See* pages 90-91. In Illinois, a decoupling mechanism was approved. However, based on the risk reduction of the mechanism, the Illinois Commerce Commission reduced ROE by ten basis points for a gas utility. A copy of the order is attached at Tab J. *See* page 101. The New York Public Service Commission adopted a decoupling mechanism, but also adjusted the ROE by 10 basis points to reflect the lower business risk to the utility. A copy of this order is attached Tab K. *See* pages 32-34. When decoupling mechanisms have been approved for electric utilities, state commissions have adjusted the ROE. *See* copies of orders from Vermont at Tab L and the District of Columbia and Tab M.

10. With respect to the position stated in response to the foregoing data request:

(a) Identify each and every factual basis relied upon by the Consumer Advocate in reaching such position;

RESPONSE:

Consistent with the General Objections above, the Consumer Advocate objects to the extent this request seeks privileged information or information protected from disclosure by attorney work product doctrine or other applicable law. Without waiving the aforementioned objections, the Consumer Advocate responds as follows: See Response to Request 9. The Consumer Advocate reserves the right to produce more information as it becomes available to it.

(b) Identify each and every legal basis relied upon by the Consumer Advocate in reaching such position;

RESPONSE:

Consistent with the General Objections above, the Consumer Advocate objects to the extent this request seeks privileged information or information protected from disclosure by

attorney work product doctrine or other applicable law. Without waiving the aforementioned objections, the Consumer Advocate responds as follows: See Response to Request 9. The Consumer Advocate reserves the right to produce more information as it becomes available to it.

(c) Identify each and every witness the Consumer Advocate intends to call to support such position; and

RESPONSE:

The Consumer Advocate Consistent with the General Objections above, the Consumer Advocate objects to the extent that no decision has been made as to what witness will testify on any particular issue in this matter. Without waiving any objection, the Consumer Advocate responds as follows: Any opinion offered by the Consumer Advocate will be based on an analysis of information that is not currently within the possession of the Consumer Advocate, but rather in possession of the Company. The Consumer Advocate has requested this information from Piedmont. In addition, the Consumer Advocate has engaged consultants; however no decision has been made to whether such consultants will be engaged to provide testimony in this docket. The Consumer Advocate reserves the right to supplement this response as information becomes available to it.

(d) Identify each and every document relating to, or reviewed or relied upon in reaching, such position.

RESPONSE:

Consistent with the General Objections above, the Consumer Advocate objects to the extent this request seeks privileged information or information protected from disclosure by attorney work product doctrine or other applicable law. The Consumer Advocate also objects to this Request as it is currently worded as being unduly broad and burdensome and beyond the scope of reasonably allowable discovery. It is unduly burdensome, unnecessary for the preparation of this Docket and practically unworkable for the Consumer Advocate to be required

to produce every document in its possession that relates to the any position it might take in this Docket or that was reviewed by any consultant or other witness it may call in the Hearing on this Docket. The Consumer Advocate will produce for Piedmont all documents relied upon by any witness in formulating any opinion to be expressed by that witness in this Docket as soon as any such witness is finally selected by the Consumer Advocate and their opinions fully formed and decided. The Consumer Advocate is well aware of the compressed time frame that was requested by Piedmont in this Docket and will do its best to finalize the witnesses it intends to call and supplement this response with the required documents as quickly as possible and as far ahead of the deadline for filing Direct Testimony as possible. The Consumer Advocate's ability to finalize its plans for presenting any witnesses in this Docket is at least partially dependent upon receiving the information it seeks from Piedmont in Discovery. The earlier that the requested information is produced for the Consumer Advocate, the earlier that the Consumer Advocate can supplement its response to this request.

Without waiving the aforementioned objections, see Response to Request 9. The Consumer Advocate reserves the right to supplement this request as information becomes available and an analysis is performed

(e) Identify what method or evaluation tools the Consumer Advocate contends should be utilized to quantify an adjustment to Piedmont's rate of return and why such methods or tools are appropriate.

RESPONSE:

Any opinion offered by the Consumer Advocate will be based on an analysis of information that is not currently within the possession of the Consumer Advocate, but rather in possession of the Company. The Consumer Advocate has requested this information from Piedmont. The Consumer Advocate reserves the right to supplement this request as information becomes available and an analysis is performed.

11. State the Consumer Advocate's position on the issue whether Piedmont should be required to meet specific, verifiable, measurable energy efficiency goals and/or benchmarks for any approved conservation programs.

RESPONSE:

The Consumer Advocate would submit that specific, verifiable, measureable energy efficiency goals and/or benchmarks are essential to the success of any conservation program. Utility conservation programs are the lynch pin of most, if not all, decoupling proposals. If conservation programs are not cost-effective, producing verifiable and measurable results, then there is simply no logical justification for a decoupling mechanism. Further, Piedmont's proposal in this matter includes mandatory consumer funding of conservation programs. If funds from consumers are collected for these programs, they must produce cost-effective, verifiable and measurable results. In essence, as an expense category, such expenditures must be prudent in the context of just and reasonable rates.

12. With respect to the position stated in response to the foregoing data request:

(a) Identify each and every factual basis relied upon by the Consumer Advocate in reaching such position;

RESPONSE:

Consistent with the General Objections above, the Consumer Advocate objects to the extent this request seeks privileged information or information protected from disclosure by attorney work product doctrine or other applicable law. Without waiving the aforementioned objections, the Consumer Advocate responds as follows: See Response to Request 11. The Consumer Advocate reserves the right to produce more information as it becomes available to it.

(b) Identify each and every legal basis relied upon by the Consumer Advocate in reaching such position;

RESPONSE:

Consistent with the General Objections above, the Consumer Advocate objects to the extent this request seeks privileged information or information protected from disclosure by attorney work product doctrine or other applicable law. Without waiving the aforementioned objections, the Consumer Advocate responds as follows: See Response to Request 11. The Consumer Advocate reserves the right to produce more information as it becomes available to it.

(c) Identify each and every witness the Consumer Advocate intends to call to support such position; and

RESPONSE:

The Consumer Advocate, consistent with the General Objections above, the Consumer Advocate objects to the extent that no decision has been made as to what witness will testify on any particular issue in this matter. Without waiving any objection, the Consumer Advocate responds as follows: At this time, it is possible Terry Buckner may provide testimony in support of Piedmont's conservation programs or in support of alternative conservation measures or modifications. Any opinion offered by the Consumer Advocate will be based on an analysis of information that is not currently within the possession of the Consumer Advocate, but rather in possession of the Company. The Consumer Advocate has requested this information from Piedmont. In addition, the Consumer Advocate has engaged consultants; however no decision has been made to whether such consultants will be engaged to provide testimony in this docket.

(d) Identify each and every document relating to, or reviewed or relied upon in reaching, such position.

RESPONSE:

Consistent with the General Objections above, the Consumer Advocate objects to the extent this request seeks privileged information or information protected from disclosure by attorney work product doctrine or other applicable law. The Consumer Advocate also objects to

this Request as it is currently worded as being unduly broad and burdensome and beyond the scope of reasonably allowable discovery. It is unduly burdensome, unnecessary for the preparation of this Docket and practically unworkable for the Consumer Advocate to be required to produce every document in its possession that relates to the any position it might take in this Docket or that was reviewed by any consultant or other witness it may call in the Hearing on this Docket. The Consumer Advocate will produce for Piedmont all documents relied upon by any witness in formulating any opinion to be expressed by that witness in this Docket as soon as any such witness is finally selected by the Consumer Advocate and their opinions fully formed and decided. The Consumer Advocate is well aware of the compressed time frame that was requested by Piedmont in this Docket and will do its best to finalize the witnesses it intends to call and supplement this response with the required documents as quickly as possible and as far ahead of the deadline for filing Direct Testimony as possible. The Consumer Advocate's ability to finalize its plans for presenting any witnesses in this Docket is at least partially dependent upon receiving the information it seeks from Piedmont in Discovery. The earlier that the requested information is produced for the Consumer Advocate, the earlier that the Consumer Advocate can supplement its response to this request.

Without waiving the aforementioned objections, See Response to Request 11 and comments and reports contained in Docket 06-00309. Further, the Consumer Advocate's investigation in this matter is on-going. No specific, verifiable, measurable energy efficiency goals have been identified. The Consumer Advocate has requested pertinent information regarding the proposed conservation program from the Company in order to evaluate the need for and scope of specific, verifiable, measurable energy efficiency goals.

13. Identify each and every specific, verifiable, measurable energy efficiency goals that the Consumer Advocate's contends Piedmont should be required to meet for any approved the benchmark for Piedmont's proposed decoupling mechanism.

RESPONSE:

See Response to Request 11. Further, the Consumer Advocate's investigation in this matter is on-going. No specific, verifiable, measurable energy efficiency goals have been identified. The Consumer Advocate has requested pertinent information regarding the proposed conservation program from the Company in order to evaluate the need for and scope of specific, verifiable, measurable energy efficiency goals. The Consumer Advocate reserves the right to supplement this request as information becomes available and an analysis is performed.

Respectfully Submitted,

ROBERT E. COOPER, JR., BPR # 10934
Attorney General and Reporter

RYAN L. MCGEHEE, BPR #025559
Assistant Attorney General
C. SCOTT JACKSON, BPR# 011005
Senior Counsel
Office of the Attorney General
Consumer Advocate and Protection Division
P.O. Box 20207
Nashville, Tennessee 37202-0207
Telephone: (615) 532-5512
Fax: (615) 532-2910

Dated: October 26, 2009.

CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the foregoing foregoing was served via U.S. Mail or electronic mail upon:

Jane Lewis-Raymond
Piedmont Natural Gas Company, Inc.
P.O. Box 33068
Charlotte, NC 28233

R. Dale Grimes
Bass, Berry & Sims PLC
315 Deaderick Street, Suite 2700
Nashville, TN 37238-3001

James H. Jefferies IV
Moore & Van Allen PLLC
100 North Tryon Street, Suite 4700
Charlotte, NC 28202-4003

This the 26 day of October, 2009.

Ryan L. McGehee
Assistant Attorney General

ATTACHMENT A

Exhibit 2

STATE OF IOWA

DEPARTMENT OF COMMERCE

UTILITIES BOARD

IN RE: INQUIRY INTO THE EFFECT OF REDUCED USAGE ON RATE-REGULATED NATURAL GAS UTILITIES	DOCKET NO. NOI-06-1

ORDER ADDRESSING ISSUES AND CLOSING DOCKET

(Issued December 18, 2006)

On February 9, 2006, the Utilities Board (Board) initiated an inquiry into the effect of reduced natural gas usage resulting from increased energy efficiency and other factors over the next five years on the non-gas revenues of Iowa's rate-regulated natural gas utilities. The Board indicated that Iowa had joined with seven other states, Michigan, Minnesota, Missouri, Wisconsin, Ohio, Illinois, and Indiana, to form the Joint Natural Gas Price Reduction Initiative (JNGPRI) to support regional and individual state actions to create downward pressure on natural gas prices by reducing demand for natural gas by 5 percent over the next five years. The Board indicated that the states recognized that the high cost of natural gas created a financial hardship on many consumers and represented millions of dollars exported from these state economies.

The Board stated that the inquiry would investigate the potential effects of this initiative and other factors in reducing natural gas usage, the resulting effect on regulated non-gas utility revenues, and would consider whether traditional regulation

is flexible enough to address these effects or whether alternative mechanisms or approaches, such as a decoupling mechanism to reduce the influence of sales volumes on utility earnings, might be appropriate. The Board presented a set of initial questions in the February 9, 2006, order for participants to address. Responses to the questions were filed by the Consumer Advocate Division of the Department of Justice (Consumer Advocate), Atmos Energy Corporation (Atmos), the Iowa Environmental Council (IEC), Interstate Power and Light Company (IPL), MidAmerican Energy Company (MidAmerican), Ag Processing Inc (AGP), the Iowa Industrial Energy Group (IIEG), and Aquila, Inc., d/b/a Aquila Networks (Aquila). As part of the inquiry, the Board contracted with the Regulatory Assistance Project (RAP) to conduct a workshop on May 10, 2006, addressing mechanisms considered in other jurisdictions to resolve these issues.

On July 11, 2006, the Board issued an order requesting responses to additional questions. The Board indicated that it had reviewed the initial comments, RAP presentation, and the discussions at the workshop and, based upon that information, the Board had questions about some of the mechanisms that were discussed. AGP, Consumer Advocate, MidAmerican, IPL, IIEG, and Aquila filed additional comments.

In considering whether a decoupling mechanism or similar system should be adopted in Iowa, the Board is faced with two important public policy concerns. First, there is the public policy goal of reducing usage of natural gas by individual customers with the result that overall usage in Iowa, and nationally, is reduced.

Second, there is the requirement under public utility regulation that a utility be given a reasonable opportunity to earn the return authorized by the regulatory agency. In many states these two public policy concerns have been found to be in conflict and various mechanisms to decouple sales of natural gas from a utility's revenues have been proposed to alleviate the tension between the two policies.

Based upon the information reviewed by the Board in this docket, the tension between energy efficiency and Iowa natural gas utilities' opportunity to earn their authorized rate of return does not appear to be a substantial problem in Iowa. Iowa utilities have been participating in energy efficiency plans since before 1990 without substantial adverse effects on earnings. In that year, Iowa established a statutory goal in Iowa Code § 473.3 to "more efficiently utilize energy resources . . . to decrease the state's dependence on energy resources from outside the state by reducing the amount of energy used." This goal was to be implemented through the development of programs that promote energy efficiency and energy conservation by all Iowans.

To meet this statutory goal, the Board developed rules and procedures for planning and implementing energy efficiency programs by Iowa public utilities and has approved several rounds of energy efficiency plans for rate-regulated utilities, most recently in 2003. The energy and peak capacity saved by investor-owned utility energy efficiency programs over the past 15 years have resulted in a cumulative reduction in natural gas usage through 2005 of about 7 million MCF, or about 6.6 percent of annual retail natural gas sales. By 2005, total customer retail cost savings

resulting from these cumulative changes in energy use amounted in 2005 to about $80 million in natural gas costs. From this, the Board concludes that Iowa utilities have not been unable to engage in meaningful energy efficiency programs because of concern about their earnings.

The Board is committed to the continuation of the aggressive energy efficiency programs already in place and to the development of new plans to further increase savings to customers and reduced natural gas consumption from increased energy efficiency. This increase in energy efficiency programs by utilities and their customers may have an adverse effect on the ability of rate-regulated utilities to have a reasonable opportunity to earn their authorized rates of return, potentially creating a disincentive to utility participation in these programs.

Other jurisdictions that lack the energy efficiency mandate and history of Iowa have adopted decoupling mechanisms. The Board believes this may be appropriate in situations where reduced natural gas usage resulting from energy efficiency programs may aversely affect earnings. When this situation exists, utilities should be able to propose appropriate mechanisms to provide the utilities with a reasonable opportunity to earn their authorized rates of return in spite of reduced sales volumes. The information reviewed in this inquiry does not demonstrate that situation for Iowa utilities to date, but the Iowa utilities in this docket have nonetheless proposed several different alternatives solutions to declining customer usage, perhaps in anticipation of increased emphasis on energy efficiency programs. The suggested

changes included rate design proposals, incentive mechanisms, and automatic rate adjustments, among other things.

One reason that Iowa utilities may not be subject to the same pressures as utilities in other jurisdictions is that the Board allows recovery of the costs associated with approved energy efficiency plans through an automatic adjustment mechanism for natural gas utilities, the Energy Efficiency Cost Recovery (EECR). This pass through of energy efficiency plan costs alleviates some of the disincentive for utilities to promote greater energy efficiency by customers. The Board recognizes that the EECR may not be a complete answer, however, as it compensates utilities for expenditures but does not address the possible adverse effect reduced energy consumption might have on utility returns.

Information reviewed by the Board in this docket concerning Iowa natural gas utilities shows that Iowa rate-regulated utilities have experienced a reduction in average customer usage over the past ten years, as have utilities in other jurisdictions. The information does not indicate that reduced usage has substantially adversely affected utilities' net operating income. The Board examined annual reports from 1995 to 2005 for each of the four rate-regulated natural gas utilities showing the average residential usage by utility from 1995 to 2005, the net operating income of each utility over the same period, and the relationship between weather and total purchases of natural gas by utility over the same period. The data shows that average residential customer usage has declined and total purchases have declined while winter weather has generally been warmer than normal over the past

several years. The data does not show a direct correlation between net operating income and declining customer usage as a result of energy efficiency programs to date.

However, it is unclear whether updated, more aggressive programs will change this situation. Each utility is likely to be affected differently, so each utility's situation should be considered separately. Separate consideration for each utility will allow the Board to determine whether any decline in net operating income is the result of a decline in customer usage due to increased energy efficiency or some other factor.

The Board believes decoupling mechanisms or rate design changes are appropriate when the circumstances support the need for such mechanisms. Some of the decoupling mechanisms that have been adopted in other jurisdictions are similar to the automatic adjustment mechanisms that are provided for pursuant to Iowa Code § 476.6(8). The Board has adopted these types of mechanisms to respond to costs that the utility management has little or no control over, that are volatile (i.e., subject to sudden and important changes in level), and that are an important factor in determining the total cost of service to customers. Under this statutory authority, the Board has adopted automatic adjustments for the purchase of natural gas, the purchased gas adjustment (PGA), and for fuel costs for electricity, the energy adjustment clause (EAC). The Board has also adopted an automatic adjustment mechanism, the EECR, pursuant to Iowa Code § 476.6(16), that

authorizes the recovery of the costs of implementing an energy efficiency plan approved by the Board.

At this time, the Board considers the standards established for the automatic adjustment mechanisms listed above to be the appropriate standards for considering whether there is a need for an automatic adjustment mechanism to compensate a utility for reduced customer usage because of increased energy efficiency. The decoupling mechanisms reviewed by the Board in this docket did not effectively identify the effect of increased energy efficiency by customers and often included other factors in the determination of when an adjustment would be made. The Board understands there may be a need by a utility to remove any disincentives that would limit promotion of increased energy efficiency, however, decoupling mechanisms that adjust for other factors may go beyond what the Board considers to be reasonable.

A review of the decoupling mechanisms suggested by the participants shows there was not a general consensus supporting use of decoupling mechanisms or a single type of mechanism. Since there was a lack of consensus, the Board will not attempt to establish a single, specific automatic adjustment mechanism that would be applicable to all of the rate-regulated utilities. Instead, the Board will encourage each utility to review its circumstances and determine if increased energy efficiency and reduced customer usage have caused, or are likely to cause, a decline in net operating income. If a relationship is shown, the utility should develop a proposal that may include an automatic adjustment mechanism, rate design change, or other solution that it considers reasonable to address the situation and should make the

appropriate filing with the Board for consideration in an appropriate proceeding. Since each rate-regulated utility will make a separate determination of whether it should make a filing and those filings will be considered in separate dockets, no further action is required in this docket. Docket No. NOI-06-1 will therefore be closed.

IT IS THEREFORE ORDERED:

Docket No. NOI-06-1 is closed.

UTILITIES BOARD

/s/ John R. Norris

/s/ Diane Munns

ATTEST:

/s/ Judi K. Cooper
Executive Secretary

/s/ Curtis W. Stamp

Dated at Des Moines, Iowa, this 18th day of December, 2006.

ATTACHMENT B

Exhibit 3

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF NEW MEXICO FOR A REVISION TO ITS RATES, RULES, AND CHARGES PURSUANT TO ADVICE NOTICE NOS. 755 AND 756, PUBLIC SERVICE COMPANY OF NEW MEXICO, Petitioner.	)	Case No. 06-00210-UT

RECOMMENDED DECISION OF THE HEARING EXAMINER

Lee W. Huffman, Hearing Examiner for this case, submits this Recommended Decision to the New Mexico Public Regulation Commission ("Commission" or "NMPRC") pursuant to 17.1.2.32.E(4) and 17.1.2.39.B NMAC. The Hearing Examiner recommends that the Commission adopt the following Statement of the Case, discussion, findings of fact, conclusions of law and decretal paragraphs in its Final Order. A Table of Contents has been included for convenience of reference.

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2. PNM's Decoupling Proposal

PNM proposes in this case to break the historic link between its sales volumes and the revenues it receives. It would do so on a per customer basis. Tr. 12/14/06, pp.85, 158-159. Quite simply, if an existing residential customer reduces their natural gas use by half, under PNM's decoupling proposal that customer would still pay the same full amount to PNM that the customer paid when PNM delivered twice as much gas to the customer. Tr. 12/14/06, p.233. The customer would always pay for the actual amount of natural gas used at the market price[16], but their individual conservation efforts would not affect the 1/3 of their bill that covers PNM's services. PNM's revenues and profits depend entirely on its authorized charges for these delivery (transmission and distribution) services.

As it stands now, about one third of a typical customer's bill is for the basic services PNM provides of delivering natural gas through its system to its customers. PNM's proposal, variously called decoupling or a Consumption Normalization Adjustment ("CNA") would be placed in its rates via proposed Rate Rider 16 ("RR 16"). It would only apply to PNM's residential and small commercial customers. It would not apply to PNM's other rate classes, such as large commercial and industrial customers. These large customers are NMIEC's membership and even though decoupling would not apply to its members, NMIEC's primary focus in this case is its opposition to decoupling.

[16] PNM does not make any profit on the sale of natural gas to its retail customers. PNM charges its customers exactly what PNM pays for the gas. There is no markup, no profit, just an exact pass-through of PNM's costs. The mechanism for this arrangement is the Purchased Gas Adjustment Clause or PGAC. Typically, the gas charge or commodity portion is about 2/3 of a residential customer's bill. The commodity price of natural gas is not regulated and reflects the operation of market forces. Tr. 12/14/06, p.174.

Every intervenor group in this case that represents PNM's customers opposed decoupling or RR 16. They are the AG, NNSA, CANM, NMIEC (all of whom testified against the proposal) and UNM, whose witness did not testify concerning decoupling, but UNM argued against decoupling in its Briefs. NRDC/SWEEP and Staff supported decoupling, but Staff expressed concern about the legal issues of whether RR 16 constitutes retroactive ratemaking and whether it is consistent with the prior hearing requirement before changing rates of NMSA 1978, Section 62-8-7(E). Also, Staff suggested that the reduction of risk for PNM that decoupling would cause should be reflected, if decoupling is approved, in PNM's allowed return on equity.

In support of its decoupling proposal, PNM relies in large measure on the Efficient Use of Energy Act ("EUE"). NMSA 1978, Section 62-17-1, *et seq*. (2005). The Act provides in Section 62-17-3 (emphasis supplied) that: "It is the policy of the Efficient Use of Energy Act that **public utilities ... include cost-effective energy efficiency and load management investments in their energy resource portfolios and that any regulatory disincentives that may exist to public utility investments in cost-effective energy efficiency and load management are eliminated."**

The EUE requires that the Commission determine whether there are any regulatory disincentives to such utility investments and if the Commission finds that there are, the Commission is further required to eliminate such regulatory disincentives. **"The commission shall identify any disincentives or barriers that may exist for public utility expenditures on energy efficiency and load management and, if found, ensure that they are eliminated in order that public utilities are financially**

neutral in their preference for acquiring demand or supply-side utility resources." NMSA 1978, Section 62-17-5(F) (2005) (emphasis supplied).

The Commission has not made any findings that such barriers or disincentives exist. PNM and NRDC ask the Commission to do so in this case. Before reaching that question, we turn to PNM's central position concerning decoupling.

PNM claims that its decoupling proposal is necessary[17] to carry out the purposes of the Efficient Use of Energy Act. The policy of the EUE requires PNM, and other utilities (gas and electric), to make certain types of energy efficiency and load management investments and it requires the Commission to first determine if any disincentives or barriers exist to such utility investments, and second, if found, to eliminate them so "public utilities are financially neutral in their preference for acquiring demand or supply-side utility resources."

PNM argues it needs decoupling to eliminate the disincentive it now has to reduce its sales volumes. PNM depends on the sale of a certain volume of natural gas to recover its fixed costs. The customer charge for residential customers covers about 45% of PNM's fixed costs and is imposed regardless of the amount of gas used. Tr. 12/14/06, p.162. PNM points out that if it invests in energy efficiency or load management programs, customers will reduce their natural gas use and thus reduce PNM's revenues, recovery of fixed costs and consequently its profits. PNM's primary witness concerning decoupling, Mr. Feingold, testified that "proposed Rate Rider No. 16 should be viewed as a means to eliminate disincentives associated with PNM's efforts

[17] PNM's decoupling witness agreed that RR 16, PNM's proposal, is "not the only one, but it's the most effective one to eliminate the ... disincentive which is the throughput incentive that a utility has." Tr. 12/14/06, p.158.

to promote energy efficiency and conservation programs such as its Residential Gas Energy Efficiency Program...." PNM Exhibit 15 (Feingold Direct), p.5.

PNM Vice President Melvin Christopher explained PNM's claim of an existing incentive for increasing sales volumes (or throughput of natural gas) and corresponding disincentive to invest in programs that reduce customers' use of gas.

> With throughput we make more money. With a decrease in throughput it hits our earnings and we don't make money. That is a significant disincentive. The efficient use of energy act is encouraging a reduction in usage by customers and encouraging the company or requiring the company to put into place programs that will lead to a decrease in throughput. That is a clear disincentive and a clear disincentive for the company....

Tr. 12/13/06, p.64.

As written, RR 16 would protect PNM from any reduction in consumption due to ratepayer actions, including those completely unrelated to PNM's energy efficiency programs such as customer reaction to the increased price of gas, general economic conditions, and customer actions such as turning down the thermostat. NMIEC Exhibit 3 (Dirmeier Direct), pp.11-12.

PNM witness Feingold admits that his decoupling proposal, RR 16, will adjust rates on a monthly basis for fluctuations in PNM's actual gas volumes which are "caused primarily by the energy efficiency and conservation efforts of [PNM's] customers and variations from 'normal' weather." PNM Exhibit 15 (Feingold Direct), p.4. PNM's own recent conservation and efficiency efforts are not even one of the causes of the significant decline in gas use per customer over the last ten years, because PNM had no gas efficiency program in place during this time. Tr. 12/14/06, pp.141-142.

As a result, PNM would be automatically compensated for any reduction in per customer use, including the customer response to high gas prices. Tr. 12/14/06, p.150. The EUE was enacted, NNSA, NMIEC, the AG and UNM argue, to eliminate disincentives to public utility expenditures on energy efficiency and load management programs, not to give PNM an automatic rate adjustment mechanism to compensate it for lost revenues no matter what caused the loss.

Mr. Feingold admitted at the hearing that the need for his revenue decoupling mechanism had two causes, "the margin losses associated with declining use per customer and the need to eliminate the throughput incentive...." Tr. 12/14/06, p.222. Despite selling less natural gas per customer, PNM's overall revenues have increased along with customer growth. Between 1998 and 2003, PNM added over 37,000 new customers and its total revenues from residential customers exceeded its corresponding rate case revenue by over $34 million. *Id.*

PNM witness Feingold states that Rate Rider 16 is the recommended ratemaking solution to ensure PNM's financial performance is not negatively impacted by the actions of its customers in response to its Residential Gas Efficiency Program and additional energy efficiency program it expects to implement in the future. PNM Exhibit 15 (Feingold Direct), p.5. But PNM witness Christopher acknowledges that the purpose of the decoupling mechanism is to compensate PNM when "customers practice conservation, implement energy efficiency measures, or consume less gas in response to warmer winter temperatures..." PNM Exhibit 1 (Christopher Direct), p.8. And PNM witness Fernald recognized that the "first and most likely contributor to reduced

consumption is the very sharp increase in natural gas prices...." PNM Exhibit 25 (Fernald Direct), p.35.

PNM's solution to its posited disincentive is overbroad. Assuming PNM has such a disincentive, and assuming the Commission were to agree and require its elimination in this case, the EUE requires the elimination of "any disincentives or barriers" to the required utility investments. The Act does not require, or even contemplate, insulating PNM's revenue recovery from any and all causes. The EUE mentions "utility expenditures on energy efficiency and load management." Section 62-17-5(F). It requires, if a disincentive is found, that utilities be made financially neutral as to whether they prefer "demand or supply-side utility resources." The Act does not require that they receive the same amount of money from a customer who chooses to use less gas.

The scope of PNM's decoupling proposal is remarkably broad. At the hearing, PNM witness Feingold agreed that his Rate Rider 16 is much broader than protecting PNM's financial performance from customer response to PNM's residential energy efficiency program. Tr. 12/14/06, p.142. Decoupling protects PNM regardless of why per customer revenues decrease. *Id.* at pp.160-161. Mr. Feingold agreed that the EUE does not mention decoupling or protecting a utility from weather risk (*Id.* at p.68), or lost sales due to higher gas prices or fuel switching. *Id.* at pp.70-71. Even so, his proposed solution of removing the throughput incentive is broad enough, in his opinion, to protect PNM from all such risks.

"I said those words are not in the Act, but my reading of the removing of disincentives supports the fact that the throughput incentive, which is the utility's ability to earn more or generate more revenues as volumes increase, is something that needs

to be removed before a utility can go forward aggressively with energy efficiency and conservation programs. **So to me that throughput incentive embodies all factors related to use per customer.**" Id. at p.69. (emphasis supplied). Mr. Feingold's focus is on use per customer, and his decoupling proposal "Rate Rider 16 is premised on use per customer." Id. at p.85. His premise finds no support in the EUE.

This single-minded focus on use per customer ignores PNM's overall economic picture and has negative consequences for customers. The EUE requires that a utility be made financially neutral. PNM's decoupling proposal is designed to be a financial windfall[18] instead.

Mr. Feingold defines "margin revenues" as "the non-gas cost-of-service for the utility that is approved in the last rate case." Id. at p.86. He uses the term to mean the total non-gas revenue requirement approved in the last rate case. Id. at p.197. His RR 16 "only uses the customers approved in ... the Company's last rate case." Id. at p.88. PNM's decoupling proposal does not take into account revenue contributions of new customers. Id. at p.126. Mr. Feingold agreed that use per customer can decline but PNM can still recover its margin revenue. Id. at p.129. This decline in use per customer triggers an upward adjustment (an increased charge) even when new customers exactly make up for reduced total use by old customers, so that the throughput, or volume of gas PNM sells, is the same. Id. at pp.122-125. In other words, under PNM's decoupling proposal, when PNM sells precisely the same amount of gas because of customer growth and there is no reduction in throughput or revenues,

[18] "I think ... that although the adjustments to any one customer is not large relative to the customer's overall bill, when you add up all of those adjustments for the customers that the company serves, that ... can have a material impact on the ability for the company to recover the revenues approved by the Commission." Tr. 12/14/06, p.80.

according to PNM witness Feingold, the "decline in use per customer when compared to the rate case number generates the need for an upward adjustment [increase] to compensate the company for that loss in revenue." *Id.* at pp.124-125. But there is no loss in revenues, just a decrease in revenue per customer.

Under the decoupling proposal PNM will be "compensated" for lost revenues even when revenues do not go down. They will also be compensated, under Mr. Feingold's decoupling proposal, when use per customer declines, but total revenues are higher than those approved in the previous rate case. Under this scenario, customers will still be assessed a surcharge. *Id.* at p.160.

The only way to receive a credit is if per customer use increases, as can happen during very cold weather. PNM points to the resulting stabilizing effect on bills, which would be lower during cold winters and higher during mild winters, as a benefit to customers. This benefit would, over the last five years, have come with a price. The cost to PNM's customers would have been over $16 million. Moreover, PNM's customers have significantly reduced per customer gas use in recent years, primarily in response to higher natural gas prices. The effectiveness of the price signal and of the customer conservation response would be reduced by decoupling.

PNM will be compensated for "losses" that do not occur, and even when the "losses" per customer are accompanied by an increase in total revenue, PNM will be compensated for these losses, too. And all of this is accomplished with decoupling's simple true-up mechanism. Mr. Feingold describes all of this as necessary: "we have to move towards a new ratemaking paradigm...." *Id.* at p.157. Other regulatory

innovations[19] have been labeled in a similar way. The results, particularly for electric restructuring, have been much higher rather than lower rates: "... Pennsylvania is not the only place where there has been some disappointment." Tr. 12/14/06, p.184. In the field of utility regulation, new paradigms have proven very expensive in the last ten years. Fortunately, the New Mexico Legislature prevented New Mexico from suffering the major electric rate increases experienced by the many states that accepted the arguments that electric deregulation would lower rates. Tr. 12/14/06, pp.184-187, 238

In recent years PNM's total throughput (volumes of gas sold and delivered) has increased due to customer growth even while the use per customer has declined. *Id.* at p.179. If decoupling had been in place during the years 2001-2005, PNM would have received an additional $16.5 million from its natural gas customers, an average of $3.3 million a year. Tr. 12/14/06, p.91. In that time frame, it did not have significant energy efficiency programs in place.

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[19] In its Order approving Formation of a Holding Company issued on June 28, 2001 in Case No. 3137 (pp.2-3) (emphasis supplied), the Commission authorized PNM to form PNM Resources ("PNMR") and recognized New Mexico's good fortune to still be among the states with traditional utility regulation.

"The Restructuring Act originally called for competition in the New Mexico retail electricity market to begin earlier this year on January 1, 2001, for residential, small business customers, and public schools and colleges, with large business starting one year later. NMSA 1978, Section 62-3A-4(A) (1999). The Legislature gave the Commission authority to delay customer choice and other dates in the Restructuring Act by up to one year. The Commission did so in an Order issued in May of 2000. But for that delay, New Mexico residents, schools and small businesses would have been at the mercy of the prevailing wholesale price for electricity for the last six months. They would no longer have been entitled under New Mexico law to electricity at just and reasonable rates."

"Because the Legislature gave the Commission authority to delay competition, New Mexicans will spend several hundred million dollars less just this year for their electricity. As New Mexico State University Professors Dr. Douglass Gegax and Dr. Paul Turner concluded in September of 2000 at a Commission Work Session on Recent Market Conditions Affecting Electricity Restructuring: 'It is interesting to note that the current regulated price path looks pretty good for New Mexico consumers.' California Electricity Markets: Lessons Learned for New Mexico, September 26, 2000, p.26."

PNM's recently established gas energy efficiency program has 934 participants out of about 470,000 natural gas residential gas customers. AG Brief in Chief, p.14. The AG also points out that PNM's gas energy efficiency program investments are funded "by a customer surcharge through a rate rider...." AG Reply Brief, p.6.

Staff witness Sisneros testified in favor of decoupling and about the complexity of determining the exact amount of lost revenues PNM would experience because of company efficiency programs. Staff Exhibit 5 (Sisneros Direct), pp.10-11. At the hearing he agreed that Staff and the parties are capable of dealing with those problems if "given adequate time and resources it's possible." Tr. 12/20/06, p.112.

The AG stressed that at hearing PNM admitted RR 16 as proposed is "flawed in that additional throughput per customer did indeed result in increased margin and thus a significant incentive to increased throughput. (Transcript, Dec. 19, p.114....)" AG Reply Brief, p.9. PNM admitted this flaw and offered to correct it. PNM Brief in Chief, p.102. "...the description would be corrected ... with that clarification, the CNA [decoupling] will eliminate the throughput incentive for PNM ... the CNA provides significant benefits to customers and the Company."

The Commission agrees that the record shows benefits of decoupling for PNM, but does not agree that it would benefit customers. PNM's proposal is inconsistent with and oversteps the EUE. It would not, as required, make PNM "financially neutral" relative to resource choices. It would, instead, give PNM insulation from a large variety of business risks including the risk of customer response to higher prices. PNM properly bears those risks. PNM's presentation on this issue is unpersuasive. PNM fails to meet its burden of proof.

The EUE requires the Commission to "identify any disincentives or barriers that may exist for public utility expenditures on energy efficiency and load management, and, if found, ensure that they are eliminated...." NMSA 1978, Section 62-17-5(F) (2005). The Act does not require approval of PNM's proposal to insulate it from the vast majority of its business risks and provide it with an "enhanced opportunity to recover its Commission-approved revenue requirement." Brief in Chief, p.104 (emphasis supplied). PNM is correct that it has an opportunity; but the legal standard is that it be a fair one, not one enhanced by an ill-advised decoupling mechanism.

The record shows that the two rate classes, small commercial and residential, that would be affected by decoupling provide PNM with almost 94 percent of its margin revenues and are about 98 percent of the total number of PNM customers. Tr. 12/14/06, p.217. A result of approving decoupling would be that at least 93 percent of PNM's total revenues would be assured of recovery. *Id.* at 218. This would put PNM in a position of having a significantly reduced overall business risk. Consistent with that position, Staff and other parties contend that PNM would then be entitled to a lower return on equity.

PNM takes a decidedly different view. PNM witness Hadaway asserts that if decoupling and a higher winter customer charge of $15.00 a month (instead of the present charge of $9.00 and PNM's proposed $11.00 charge) "were not being proposed by PNM, it would be appropriate to increase PNM's requested ROE to account for its more risky position." PNM Exhibit 18 (Hadaway Direct), p.28. He relies on the fact that his "peer group" of comparable gas utilities have decoupling. His testimony is that 5 of 10 do. Tr. 12/18/06, p.96. Which means 5 of 10 do not.

Dr. Hadaway's selection of a peer group[20] of this 50/50 composition may or may not reflect the overall industry average. *Id.* at p.97. In any event, PNM has not met its burden of proof in this case concerning decoupling. PNM, if it had decoupling, would have substantially reduced risk and very little uncertainty regarding its revenues. Under Bluefield, this situation would necessarily result in a lower rate of return than what we have determined is fair in this case. The Commission does not agree with PNM that it is entitled to a higher rate of return than what is authorized in this case.

If any other states are significantly reducing a utility's risk with a decoupling plan having the same features as PNM's proposal without reflecting the corresponding reduction in risk and revenue uncertainty in the authorized rate of return, we are not obligated to follow any such departure from established principles. Any such departure from the *Bluefield* standards raises significant issues.

PNM's proposal for decoupling and its related proposal for an increased rate of return in the absence of decoupling do not comport with the fundamental nature of utility regulation. The primary result that would flow from decoupling would be to insulate PNM's revenues from customer response to the higher prices for natural gas experienced in recent years. PNM's request to be so insulated surpasses the proper limits of utility regulation. As the United States Supreme Court explained in *Market St. Ry. Co. v. Railroad Commission*, 324 U.S. 548, 568 (1945). "Even monopolies must

[20] In future rate cases, care should be taken by PNM, Staff and others to ensure that comparable utilities are as similar to the New Mexico utility as possible. The burden will be on the proponent of a comparable group of utilities to document by a written determination by the relevant state commission of the level of any utility's revenues that are assured of recovery if the proponent asserts that the level of risk for the New Mexico utility in the subject rate case is somehow different compared to one or more members of the comparable group.

sell their services in a market where there is competition for the consumer's dollar and the price of a commodity affects its demand and use."

PNM is authorized a return on equity above a risk free rate. One of its business risks is that customers will use less natural gas, per customer, in response to higher natural gas commodity prices. The record in this case shows that despite this per customer decline, PNM's overall sales have increased[21] because of customer growth.

PNM's decoupling proposal would protect it from a wide range of business risks. And PNM wants this protection without any reduction in its authorized return on equity, despite the clear reduction in risk attendant to PNM's proposal. In declining PNM's proposals, we are mindful that an aspect of symmetry is required in utility regulation. The United States Supreme Court made it clear that a utility is entitled to consistent, symmetrical treatment. "Consequently, a State's decision to arbitrarily switch back and forth between methodologies in a way which required investors to bear the risk of bad investments at some times while denying them the benefit of good investments at others would raise serious constitutional questions." *Duquesne Light Co. v. Barasch*, 488 U.S. 299, 315 (1989). Accepting either of PNM's proposals would raise a serious issue concerning that required symmetry.

Although PNM has offered to "fix" the flaw in RR 16, the shortcomings of RR 16 are not amenable to any fix. It goes beyond what the EUE authorizes or requires and it suffers from other shortcomings as well.

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[21] Since early 2003, the average residential cost-of-service component of a bill is now 2.8 percent lower, but over the same timeframe PNM has added 30,000 new customers, an increase of between 6 and 7 percent. Tr. 12/13/06, pp.79, 85.

The parties identified additional problems with PNM's decoupling proposal. They argue it violates the requirement of NMSA 1978, Section 62-8-7(E) that there be a hearing before there is a change in rates, except in the case of several specific cost factors. PNM argues the EUE creates an exception to this hearing requirement. PNM's position is incorrect. A change in sales volumes is not one of the identified exceptions.

PNM's request is contrary to the well-settled doctrine that "where a statute explicitly enumerates certain exceptions to a general grant of power, courts should be reluctant to imply additional exceptions in the absence of a clear legislative intent to the contrary." U.S. v. NEC Corp., 931 F.2d 1493, 1502 (11th Cir. 1991); Davis v. Davis, 911 F.2d 560, 562 (11th Cir. 1990) (courts "are not free to create by interpretation an exception in a statute which is plain on its face"); Cottonwood Mall Shop. Ctr., Inc. v. Utah Power & Light Co., 440 F.2d 36, 40 (10th Cir. 1971), cert. denied, 404 U.S. 857 (1971) (State public utility statutes "must be given a liberal reading to provisions subjecting the activity to regulation while simultaneously giving a more narrow scope to the exceptions"); see also, State v. Board of County Commissioners, 62 N.M. 137, 140-141, 306 P.2d 259 (1957) (anyone claiming the benefit of an exemption must clearly and unmistakably establish his right to it).

Section 62-8-7(E) provides as follows. "Except as otherwise provided by law, any increase in rates or charges for the utility commodity based upon cost factors other than taxes or cost of fuel, gas or purchased power ... shall be permitted only after notice and hearing...." PNM argued it is not changing cost factors so Section 62-8-7(E) does not apply. The AG responds that PNM wants decoupling to recover its costs, and that to "be just and reasonable, rates must be cost-based." Reply Brief, p.10. We agree

with the AG and note that PNM would increase its delivery (transmission and distribution) rate under RR 16 based on the reduction in the amount of gas a customer uses.

The parties also contend that decoupling would discourage ongoing customer-initiated conservation efforts. In effect, under decoupling customers could no longer reduce what they pay to PNM for transmission and distribution. They would only save on the commodity portion of their bill. PNM's reaction is to dismiss as relatively small the additional costs decoupling would impose on customers who voluntarily reduce their own use of natural gas. A PNM customer who conserves on their own will not have the savings associated with a reduction in throughput and Mr. Feingold considers that amount minimal. Tr. 12/14/06, p.235. Earlier, he expressed his opinion on the present treatment afforded PNM's natural gas customers who conserve. "Quite frankly, the way the rates are designed currently, I believe that customers are overpaid to the extent that they reduce their energy consumption by virtue of the fact that they are saving on fixed costs through the variable portion of the rate where that shouldn't be happening." *Id.* at p.231.

The Commission does not agree that customers who conserve are "overpaid" under the present rate design. The record shows that PNM's customers would have paid an extra $16.5 million between 2001 and 2005 had decoupling, as proposed by PNM, been in place. We consider this evidence sufficient to conclude that decoupling would discourage conservation efforts. PNM's proposal is inconsistent with the EUE.

Additional issues such as whether decoupling is inconsistent with regulatory lag or whether it would constitute retroactive ratemaking may have merit but need not be

decided in this case. The Commission finds that decoupling is not in the public interest and is inconsistent with the Public Utility Act.

The EUE requires the Commission to make certain determinations. They apply not just to PNM's natural gas service, but to all natural gas and electric utilities in New Mexico. We will make the necessary determinations in a separate case, one devoted exclusively to those issues. The other affected electric and natural gas utilities will be able to fully participate in that case. The testimony and argument provided in this case, and the Commission's decisions, serve to inform and guide Utility Division Staff and potential parties to that later case of certain issues to be considered and what approaches have already been considered and rejected.

Finally, we note that PNM in its Brief in Chief (p.6) identifies nine states that have decoupling for natural gas utilities, several of which are using a three-year pilot program. PNM suggests a three-year pilot program for New Mexico as an alternative to its proposal. We do not know the details of the decoupling plans in use in those nine states (or how many of the remaining 40 states have rejected a decoupling proposal), but the record in this case conclusively demonstrates that a pilot program is not needed in New Mexico because PNM's decoupling proposal is fatally flawed.

3. Conservation Adjustment

PNM requests that if decoupling is denied, the Commission grant it an annual increase to test period revenues of $2,855,503. The basis for PNM's request is that it wants the increase in revenue requirement to "reflect the impact of a significant decline in per customer usage during the winter of 2005/2006 .... PNM believes that the reduction in usage was a direct result of higher natural gas prices and PNM's efforts to

ATTACHMENT C

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
PUBLIC UTILITIES COMMISSION

IN RE:

APPLICATION FOR RATE CHANGE
PURSUANT TO R.I.G.L. §§ 39-3-10 AND
39-3-11 OF NARRAGANSETT ELECTRIC
D/B/A NATIONAL GRID

DOCKET NO. 3943

DECISION AND ORDER

DATED: January 29, 2009

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
PUBLIC UTILITIES COMMISSION

IN RE:

NATIONAL GRID GAS APPLICATION TO IMPLEMENT NEW RATES — DOCKET NO. 3943

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STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
PUBLIC UTILITIES COMMISSION

IN RE:

APPLICATION FOR RATE CHANGE PURSUANT TO R.I.G.L. §§ 39-3-10 AND 39-3-11 OF NARRAGANSETT ELECTRIC D/B/A NATIONAL GRID

DOCKET NO. 3943

DECISION AND ORDER

I. INTRODUCTION

On April 1, 2008, The Narragansett Electric Company d/b/a/ National Grid (the "Company") filed an application to increase the Company's base distribution revenues for the first time in almost ten years. The Company proposed an increase of $20.04 million, or 4.6% of total gas revenues, representing an additional $72 per year for a typical residential heating customer using 922 therms of energy. The primary factors cited by the Company in support of its rate increase application were increased operation and maintenance expenses, and the need to compensate for historic underinvestment by prior management in the distribution infrastructure. The Company also cited a need to address a loss of revenue due to increasing customer conservation over the years. The Company calculated that it had experienced annualized lost revenues totaling $7.64 million since June 2004 for the residential heating class alone.

The Company's rate application included a request that the Commission consider an important policy issue of first impression in Rhode Island: whether the Company's allowed distribution revenues should be decoupled from the volume of natural gas consumption by its customers. Under traditional ratemaking in Rhode Island and most of the United States,

distribution revenues are based on a volumetric charge established by the regulatory agency. To obtain an increase in the volumetric charge, and a resulting increase in revenues, the utility must in general file a base rate case and demonstrate to the satisfaction of the regulators that the utility's costs and expenses justify an increase. Fifteen states have allowed utilities to modify the volumetric distribution charge approved in a base rate case up or down as needed for the utility to collect an approved amount of distribution revenues, without further review by the regulatory agency. The parties and the Commission devoted considerable time and attention to understanding the advantages and disadvantages to ratepayers of the Company's decoupling proposal.

A. Conduct of the Proceeding.

The record in this case is unusually extensive and complex, addressing as it does numerous contested technical and financial issues as well as broad disputes over important issues of public and ratemaking policy. The Company's initial filing alone totaled over 1,000 pages of testimony and supporting documentation. In response to the Company's base rate application, the Commission received and considered voluminous and detailed pre-filed testimony and exhibits from experts employed by the Division of Public Utilities and Carriers ("Division"). Several intervenors requested and were granted permission to participate in the proceeding, including the Rhode Island Attorney General, the Rhode Island Office of Energy Resources, the George Wiley Center, Conservation Law Foundation, Environment Northeast, the Energy Council of Rhode Island, and Rhode Island Hospital. The intervenors submitted additional written testimony and exhibits. The Commission's review and consideration of these

voluminous materials was further complicated by the restrictive limits on communications with Commission staff recently imposed by the Rhode Island Supreme Court.[1]

After the initial filing, the parties engaged in extensive discovery proceedings. The Commission, Division and other parties propounded over 500 data requests to the Company for information relating to the Company's and its affiliates' management, operations and finances. The Company provided hundreds of pages of written answers and supplemental documentary material in response. The Company also responded to numerous record requests made during the course of the public hearings on this docket.

The Commission conducted twelve days of evidentiary hearings on the Company's proposal in September and October, 2008. Over 160 exhibits, totaling thousands of pages of information, were received into evidence. The Company, Division and other parties presented seventeen witnesses:

For the Company:

1. Nickolas Stavropoulos, Executive Vice President of Gas Distribution-US for National Grid, with responsibility for the Company's regulated gas distribution operations in Rhode Island, Massachusetts, New Hampshire and New York, testified for the Company regarding its overall business operating plan and decoupling proposal;

2. Michael Laflamme, Director of Revenue Requirements for National Grid USA Service Company, Inc., testified for the Company regarding its single year revenue requirement analysis, including sharing of net synergy savings from both the National Grid/Southern Union and National Grid/KeySpan transactions;

3. Susan Fleck, Vice President of Engineering Standards and Policy for National Grid USA, testified for the Company regarding its accelerated pipeline replacement program;

4. Peter Czekanski, Manager of Pricing for National Grid Rhode Island – Gas, testified for the Company regarding adjustments to test year billing determinants and revenues that produce rate year billing determinants, and the Company's proposed tariff changes;

[1] *See Arnold v. Lebel,* 941 A.2d 813 (R.I. 2007).

5. Sean Mongan, Director of Operations and Process Support for the Energy Solutions Service Group for National Grid USA, testified for the Company regarding its proposed Gas Marketing Program;

6. Paul Moul, Managing Consultant, P. Moul & Associates, testified for the Company regarding an appropriate rate of return;

7. Robert Hevert, President, Concentric Energy Advisors, testified on behalf of the Company regarding the effect of decoupling on an appropriate rate of return;

8. James Simpson, Vice President, Concentric Energy Advisors, testified for the Company regarding the mechanics of the Company's decoupling proposal;

9. David Heintz, Assistant Vice President, Concentric Energy Advisors, testified for the Company to explain the Company's proposed rate design for the gas business in Rhode Island;

For the Division:

10. David Effron, a consultant specializing in utility regulation, testified on behalf of the Division of Public Utilities and Carriers regarding the Company's proposed revenue requirement, the proposed pension reconciliation mechanism, and the accelerated pipeline replacement expense reconciliation mechanism;

11. James Rothschild, a financial consultant specializing in utility regulation, testified on behalf of the Division of Public Utilities and Carriers regarding the Company's proposed cost of capital with and without decoupling;

12. Don Ledversis, Gas Inspector for the State of Rhode Island, testified on behalf of the Division of Public Utilities and Carriers regarding the condition of the Company's distribution infrastructure;

13. Bruce Oliver, President, Revilo Hill Associates, testified on behalf of the Division of Public Utilities and Carriers regarding the Company's proposed revenue requirement, decoupling, non-firm distribution rates, and other rate design issues;

For the Intervenors:

14. John Farley, Executive Director, The Energy Council of Rhode Island, testified on behalf of TEC-RI regarding the Company's decoupling, low income discount and non-firm distribution rate proposals;

15. James DeMetro testified on behalf of Rhode Island Hospital regarding the Company's proposed non-firm distribution rates;

16. Seth Kaplan, Vice President for Climate Advocacy and the Director of the Clean Energy/Climate Change Program, Conservation Law Foundation, testified on

behalf of the Conservation Law Foundation regarding the Company's decoupling proposal;

17. James Grasso, President, Silent Sherpa Energy Consulting and Professional Services, Inc., testified on behalf of Silent Sherpa regarding the Company's non-firm distribution rates.

All parties, Commissioners, Commission counsel, and Commission staff were given broad latitude to examine the witnesses regarding their pre-filed direct and rebuttal testimony, and to introduce supplemental testimony and other evidence during the hearings. At the direction of the Chairman, the hearings were conducted so as to ensure a full and compete record for the Commission to consider in deciding the case.

The Commission also received and carefully considered numerous public comments. The Commission heard public comment on the Company's proposals from 30 individuals at open meetings held in Pawtucket, Woonsocket, Middletown and Warwick in June 2008: Sally McAuley, Raymond Matthew, Ernie Marot, Michael Dyer Ryan, Julie Silvia, Darlene Magaw, Joseph Pamula, Cindy Chompka, Jackie Archambault, Jim Healy, Charles A. High, Henry Shelton, John A. MacLennan, Don Mallinson, Frank Bozyan, Irene Santos, Manuel Marques, Elizabeth Dees, Bill O'Connell, Harry Bogosian, Virginia Gonsalves, Sister Carol Weaver, Stephanie Cannady, Lela Coons, Marie C. Hennedy, John Colby, Elizabeth Marsis, Maggie Rogers, Erik Dufresne and Roberta Fitton. The Commission heard additional public comment from 21 individuals during the evidentiary hearings: Julie Gill, Christopher Powell, Peter Cassels, Jan Campbell, Michael Januario, Karina Lutz, Sandra Morra, Elaine Gambardella, Stephen Kapalka, Jessica Jennings, Thomas J. Murphy, Michael Seymour, Kenneth Clark, Nancy Clark, Elizabeth Clark, Donald DeSantis, Kathie Foorsheim, Sally Lapides, David Pallante, Judith Croyle and Charles Pinning. Customers who commented were opposed to a rate increase and concerned about the effects on their households, particularly elderly and at-risk

households. Customers were also concerned about the collateral effects of rate increases on businesses, churches, schools and non-profit organizations. Several customers commented that the Company should be more aggressively trying to reduce its costs, rather than increasing rates. Other customers complained about the Company's failure to communicate adequately with customers about Company initiatives, particularly efforts by the Company to relocate gas meters to the front of customers' homes, and about deficiencies in the Company's Value Plus Installer conversion program.

After the conclusion of the hearings, the parties and intervenors submitted post-hearing briefs summarizing the arguments and evidence presented, and addressing certain legal issues presented by the Company's proposals. The Commission also received reply briefs from the parties and intervenors commenting on each others' post-hearing submissions.

B. Applicable Legal Standards

As noted above, many public commentors expressed the view that energy costs have increased significantly in recent years and that no rate increases should be allowed. The Commission takes seriously its responsibility to thoroughly review proposed rate increases, and has devoted substantial time and resources to investigating the justification for the Company's proposed expenses, ultimately reducing the Company's revenue request by a substantial amount. At the same time, the Commission must allow the Company sufficient resources to deliver safe and reliable natural gas service to approximately 250,000 customers who rely on gas in their homes and business in virtually all cities and towns statewide. The Company, like its customers, faces rising costs for the goods and services it needs to deliver natural gas. The Company's interim filings relating to increases or decreases in the commodity cost – the cost of natural gas itself – do not address these distribution costs.

The Rhode Island General Assembly has declared that it is the policy of the state

> To provide fair regulation of public utilities and carriers in the interest of the public, to promote availability of adequate, efficient and economical energy, communication and transportation services and water supplies to the inhabitants of the state, to provide just and reasonable rates and charges for such services and supplies, without unjust discrimination, undue preferences or advantages, or unfair or destructive competitive practices . . . . .

R.I.G.L. § 39-1-1; *see also* R.I.G.L. § 39-2-1 (utility rates and charges must be "reasonable and just"); R.I.G.L. § 39-2-2 (prohibiting rate discrimination). The Commission's review of the Company's proposals must be conducted taking this policy into account. The Company bears the burden of proof to show that its rate increase is necessary in order to obtain just and reasonable compensation for the service rendered. R.I.G.L. § 39-3-12. There is no single formula for measuring just and reasonable rates; the Commission has discretion to select a measurement approach that is supported by the record. *Providence Gas Co. v. Burman*, 119 R.I. 78, 376 A.2d 687 (1977).

C. Summary of Decision.

The Commission rendered its decisions on the issues presented by the parties at an open meeting on November 24, 2008. As reflected in the Company's compliance filing, the Commission's decisions in this docket result in the Company's revenue deficiency being reduced from the $20,036,103 initially proposed to $13,659,773. Thus, the Company's allowed distribution revenue will increase by 10.88% from $125,606,713 to $139,266,486. For a typical residential heating customer using 922 therms of natural gas, the approved new base rates represent an increase of $56 per year. Combined with other scheduled changes under the Gas Cost Recovery and Distribution Adjustment Clause, however, this will result in a net 4.1% rate reduction, which translates to an annual reduction of about $64 per year. The Commission denied the Company's proposed return on equity of 11.5%, finding that a lesser return of 10.5% is just and reasonable. Other regulatory adjustments include: reducing the Company's proposed

health care expense by $907,456; reducing the Company's proposed FAS 112 expense (relating to post-employment benefits other than pension) by $170,000; reducing the Company's proposed synergy savings from the Southern Union merger by $1,054,609; eliminating the Company's proposed $1,377,000 gas marketing program; and reducing the Company's proposed low income uncollectible accounts receivable adjustment by $150,000.

The Commission also (1) approved a 10% distribution rate discount for qualifying low income customers, (2) approved the Company's accelerated pipeline replacement program to address the increasing number of gas leaks in Rhode Island's aging distribution infrastructure, (3) approved the Company's proposed reconciling mechanism for pension and post-retirement benefits other than pension expense, and (4) approved distribution rates for non-firm transportation customers that will be set at a fixed percentage of 80% of the otherwise applicable firm transportation rate. The Commission rejected the Company's proposed revenue decoupling mechanism and a proposed reconciling mechanism for gas-supply related bad debt.

In granting the Company a distribution revenue increase of $13,659,773, the Commission is allowing additional funds for the Company to modernize its infrastructure and provide safe, efficient and reliable service to customers. The Commission's adjustments to the Company's proposed expenses and the revised 10.5% return the Company will be allowed to earn on its investment reflect the difficult economic conditions in the state that are faced by both the Company and its customers. The 10.88% revenue increase granted by the Commission is significantly lower than the approximately 16% increase requested by the Company; however, the Commission believes that the rates it has allowed are just and reasonable and will permit the Company to earn a fair rate of return. The Commission believes that it has properly balanced the

competing interests presented by the parties, consistent with the Commission's statutory duty under Rhode Island law.

II. SUMMARY OF THE COMPANY'S RATE FILING.

The Company's initial filing requested a base revenue increase of $20,036,103 million, to $149,885,295. Ex. NGrid 3 at 6 (Laflamme Direct). The Company developed its revenue request based on a test year ending September 30, 2007. The Company made adjustments to test year revenues and expenses to reflect "known and measurable" changes relating to any one-time, out of period or unusual activities. Ex. NGrid 3 at 7 (Laflamme). *See Narragansett Electric Co. v. Harsch*, 117 R.I. 395, 368 A.2d 1194 (1977) (Commission may accept known and measurable changes that affect test year data with certainty). The Company then made a number of pro forma changes to reflect anticipated cost and revenue changes through the end of the rate year, September 30, 2009. These include changes in labor and benefit costs, postal rate increases, adjustments for the pending sale of the Company's Providence, R.I. office, rate case expenses and inflation. The operating results were also adjusted to include operations & maintenance expense and capital costs associated with the Company's proposed Gas Marketing Program and accelerated infrastructure replacement program. Ex. NGrid 3 at 8 (Laflamme).

To calculate the $149 million of base revenues proposed in its initial filing, the Company (1) excluded actual Gas Cost Recovery revenues recorded in the Test Year, (2) adjusted interruptible firm revenues to the base rate credit level of $1.6 million, (3) eliminated actual energy efficiency surcharges recorded in the test year, (4) eliminated actual gross receipts tax collections and gross receipts tax expense recorded during the test year, (5) adjusted operating revenue related to out of period, non-recurring, unbilled and weather normalization revenues recorded in the test year, (6) adjusted for the Company's service contract program

costs, and Allowance for Funds Used During Construction and interest on customer arrears, and (7) adjusted all components of the test year base rate revenues to reflect normal weather. The Company also made pro forma adjustments to reflect total base rate revenues expected in the rate year, including adjustments to the base rate recovery component for the Low Income Heating Assistance Plan, Low Income Weatherization Program, Advanced Gas Technologies Program, and Environmental Remediation cost recovery. Ex. NGrid-3 at 9-10 (Laflamme).

To calculate the $123 million of operating expenses proposed in its initial filing, the Company (1) eliminated from the cost of service total gas expenses of $300,428,013 recorded in the test year, (2) excluded non-gas O&M expenses recovered through the GCR, (3) eliminated gas-related uncollectible expenses at the test year uncollectible rate of 2.10%, (4) corrected an accounting error associated with Environmental Remediation cost amortization, (5) excluded energy efficiency expenses and gross receipts tax expense recorded in the test year, (6) adjusted test year Y2K and legacy system amortization expense, (7) excluded an expense credit erroneously recorded in the test year, (8) included an expense credit for overhead associated with test year service contract labor, (9) eliminated certain computer hardware lease expense, (10) adjusted the Company's accrued vacation liability, (11) adjusted for a medical expense billing lag, (12) reclassified donations to other O&M categories, (13) excluded all costs to achieve merger synergies from the Southern Union and KeySpan transactions, and (14) excluded the approved merger synergy allowance from the Southern Union transaction. The Company also made pro forma expense adjustments to test year salary and wages, medical and dental expenses, group insurance expenses, pension and other post-retirement benefit expenses, employee thrift plan expenses, postage expenses, rate case expenses, office expenses, automated meter reading

expenses, LNG-related expenses, and made an inflation adjustment. Ex. NGrid-3 at 11-24 (Laflamme).

The Company made additional adjustments to depreciation expense ($911,576), municipal tax expense ($213,448), and payroll tax expense ($188,066). The Company's depreciation study resulted in a composite depreciation rate of 3.36%. Excluding the Company's investment in the Providence, Rhode Island office, the composite depreciation rate is 3.38%. This composite rate was applied to rate year depreciable plant to arrive at rate year depreciation expense. For municipal tax expense, the Company calculated a three year average percentage increase of 1.38%, and applied this rate of increase to the Company's most recent 2007 municipal tax assessment, adjusted to exclude the Providence, Rhode Island office property. Payroll tax expense was adjusted by applying the net change in rate year versus test year O&M salaries and wages to test year payroll tax expense. Ex. NGrid-3 at 40-42 (Laflamme).

The Company proposed a rate base of $285,241,458. Ex. NGrid-3 at 44 and Attachment NG-MDL-1 at 24. To calculate rate base, the Company used a five quarter average of net plant in service plus cash working capital, materials and supplies, prepayments and deferred debits, less deferred income taxes, customer deposits and an injuries and damages reserve. The Company included a hold harmless base rate credit of $30,337,343 relating to the tax asset basis step up realized by the Company upon its acquisition of the regulated Rhode Island gas assets of New England Gas Company. Both plant in service and accumulated depreciation amounts were adjusted for the anticipated sale of the Company's Providence, Rhode Island office. The Company's proposal was based on forecasted additions to plant in service of $36,679,000 in the twelve months ending September 30, 2008, and $60,780,000 in the twelve months ending September 30, 2009. Ex. NGrid-3 at 42-44 and Attachment MDL 1, p. 26 of 33.

The Company proposed an overall cost of capital of 9.27%, including a return on equity of 11.5%. Ex. NGrid-3 at 45.

The Company also requested a number of significant modifications to its tariff. These included: (1) introducing a revenue decoupling mechanism to reconcile actual annual revenue per customer with the revenue per customer approved in this rate case; (2) introducing new annual reconciling mechanisms for certain expenses previously fixed in base rates, including pension and other post-retirement benefit expense and commodity-related bad-debt expense; (3) introducing a discounted billing rate for low income customers, and (4) capping value of service pricing for interruptible service customers at 150% of the comparable firm tariff rate.

III. DECISION

A. Revenue Requirement Issues.

The Company's proposed revenue deficiency is based in part on three contested items: (1) the percentage of common equity to be included in the Company's capital structure for ratemaking purposes, (2) the appropriate cost of common equity, and (3) the allowable rate base through the end of the rate year. These items are addressed in turn below.

1. Capital Structure

The Company and the Division agree that, although the Company's Rhode Island natural gas operations are a division of The Narragansett Electric Company ("Narragansett Electric"), Narragansett Electric's actual capital structure contains a large proportion of common equity and is inappropriate for use in the ratemaking process. Ex. NGrid-9 at 10-11.[2] The

[2] Narragansett Electric is a subsidiary of National Grid USA. National Grid USA is a subsidiary of National Grid plc. The capital structure of National Grid USA and Subsidiaries as of September 30, 2007 was about 60% equity and 40% debt. The capital structure of Narragansett Electric was about 90% equity and 10% debt. Ex. NGrid-9 at 11-12 (Moul Rebuttal); Data Response COMM 3-4.

Company and the Division disagree, however, on the appropriate alternative measure. The Company proposed a capital structure of 47.71% equity, 40.63% long-term debt, and 11.66% short-term debt, calculated based on the equity ratios of a proxy group of other U.S. natural gas utilities. Ex. NGrid-8 at 4 (Moul). The Division proposed using the capital structure of the Company's parent, National Grid plc: 37.77% equity, 59.06% long-term debt, and 3.17% short term debt. Division Post-Hearing Mem. at 5; Ex. DIV-5, JAR Schedule 1 (Rothschild).

Company Position. The Company argued that its parent company's capital structure should not be used for ratemaking for several reasons. First, it would mean using the capital structure of a non-domestic, unregulated holding company that owns and operates a global operation encompassing a wide range of unregulated activities. The unregulated activities have different business risks. Ex. NGrid-9 at 9-16; Tr. 9/10/08 at 9-10. The Division's expert should have, but did not, take into account the nature of National Grid plc's unregulated activities or the reasonable range of capital structures in the United Kingdom. Tr. 9/11/08 at 74-75.

Second, the record is clear that the capital structure recommended by the Division is not typical of a capital structure for a regulated gas company operating in the U.S. *See, e.g.,* Ex. DIV-31. In that regard, the record shows that the average capital structure associated with the proxy group that the Division's witness uses for the ROE calculation has an average common equity ratio of 49.12% and the median is 47.05%. Ex. DIV-5 at Schedule JAR-7; Ex. NGrid-9 at 14; Tr. 9/10/08 at 12-13. In addition, the Division's own data shows that no regulated gas or electric utility obtaining a Commission decision on a rate case year-to-date in 2008 had a capital structure with less than 41% common equity and no regulated gas company had a common equity ratio less than 46% common equity. Ex. DIV-31 at 4-5. The average common equity

ratio was demonstrated to be 52.06%. *Id.* As a result, these factors underscore the unreasonableness of the Division's recommendation and argue for adoption of the Company's proposed capital structure.

Third, the record shows that there is a different regulatory structure in the UK and that the regulator of National Grid's UK business does not utilize the capital structure represented by its U.S. Generally Accepted Accounting Principles ("GAAP") accounts when setting rates. *Id.* at 17-18; Tr. 9/10/08 at 10-11, 50-52. Instead, rates are set in the UK based on a Regulatory Asset Value ("RAV"). The RAV has no direct relationship to the book value of the UK businesses and was derived from a combination of replacement cost and market value that is increased by inflation every year. Thus, even if it were appropriate to impute the capital structure for National Grid plc to the Rhode Island operations, which it is not, the equity component determined in accordance with the US GAAP must be adjusted to recognize the difference between the RAV and the US GAAP book value of the UK regulated businesses. This procedure is necessary to ensure that National Grid's consolidated capital structure as applied to the Company reflects the regulatory value of assets in both the US and the UK. The adjustment would increase National Grid's consolidated common equity ratio determined in accordance with US GAAP by approximately eight percentage points. Ex. NGrid-9 at 17-18.

Fourth, the record shows that, even if it were appropriate to look to National Grid plc for the capital structure, the Division's witness has not correctly stated the equity ratio for National Grid plc in accordance with U.S. GAAP. *Id.* at 15. Specifically, in calculating the parent company's capital structure, the Division's witness failed to take into account approximately $3.7 billion of cash, cash equivalents and marketable securities carried on its fiscal 2007 balance sheet. *Id.* These cash balances should have been subtracted from

outstanding debt balances to compute the capital structure ratios, but were not. *Id.* at 15-16. If this correction were made, the common equity ratio for National Grid plc would total 44.36%, and adjusted for the RAV of National Grid plc/s regulated UK businesses, the actual common equity ratio that would apply to the Rhode Island operations would be 52.19%, rather than the 37.77% incorrectly calculated by the Division's witnesses. *Id.* at 16-18.

Significantly, the Division's witness testified that he was "not aware" of the differences in the UK regulatory system before he made his recommendation on capital structure. Tr. 9/10/08 at 193. The witness further testified that he only became aware of the RAV method of dealing with rate base after receiving a response to a data request on the Company's rebuttal testimony. *Id.* at 194. The witness testified that he felt he was on "comfortable ground" with the "end result" without knowing anything about the RAV. *Id.* at 194-195. However, given the differences that do exist and are proven on the record for this proceeding, it is clear that an accurate calculation cannot be performed without knowledge of the RAV implications. Therefore, this omission has the effect of undermining the "end result" recommended by the Division's witnesses.

Division Position. In rebuttal, the Division argued that using the capital structure of National Grid plc is reasonable because (1) the debt rating of the Company's Rhode Island operations is dependent on the financial condition of the holding company, (2) the subsidiary's common equity was not raised from common equity holders, but through debt sources from the parent, (3) the holding company's A minus bond rating indicates that its capital structure is appropriate, (4) using the Company's 47% common equity ratio does not carry any value to ratepayers given that Rhode Island operations would still be financed by the UK holding company that maintains a lower equity percentage, and (5) if the Company's ratio is used, "not

only would Rhode Island ratepayers fund much more costly equity that, in reality, is never actually utilized for the Rhode Island operations, the hypothetical equity would then have to be grossed up for federal income taxes for an overall cost rate of almost 17.7%." Division Post-Hearing Mem. at 5-9; Tr. 9/11/08 at 76-77, 120-123 (Rothschild); Ex. DIV-6 at 6-7 (Rothschild Rebuttal).

Commission Decision. The Commission will use a utility's actual capital structure in setting rates, unless that capital structure is not reasonable for rate-setting purposes. If the actual capital structure is not reasonable for rate-setting purposes, the Commission may impute a capital structure consistent with market's expectations for a regulated utility. *Blackstone Valley Electric*, Order No. 13877 (1992) (using actual capital structure); *The Narragansett Electric Company*, Order No. 14857 (1995) (settlement using actual capital structure); *The Narragansett Electric Company*, Order No. 16200 (2000) (settlement using imputed capital structure); *In re New England Gas Company*, Docket No. 3401 (2002) (settlement using imputed capital structure of 43.6% common equity). The Commission finds that the Division's reliance on the actual capital structure of National Grid plc is not appropriate because the Division's expert did not make adjustments that should have been made to recognize the different treatment of regulatory assets in the U.K., or the approximately $3.7 billion of cash and equivalents on National Grid plc's balance sheet. Ex. NGrid-9 at 15, 17-18. The evidence indicated that the Division's expert was unfamiliar with U.K. accounting conventions cited by the Company until after he submitted his direct testimony. Tr. 9/10/08 at 193-195. The Company's proposed capital structure is more typical of a capital structure for a U.S. regulated gas company. Ex. DIV-5, Schedule JAR-7; Ex. NGrid-9 at 14; Tr. 9/10/08 at 12-13. For all of these reasons, the Commission approves the Company's proposed capital structure of 47.71%

equity, 40.63% long-term debt and 11.66% short-term debt based on the proxy group of other U.S. natural gas utilities.[3]

2. Return on Equity.

The Company proposed a weighted average cost of capital of 9.19% and an allowed return on equity of 11.50%. Ex. NGrid-8 at 2 (Moul). The Division proposed a weighted average cost of capital of 8.56%[4] and an allowed return on equity of 9.95%, assuming the Division's proposed capital structure. Ex. DIV-5 at 4 (Rothschild).[5] The Company proposed, and the Division did not question, continuing the existing earnings sharing mechanism for earnings above the allowed rate of return. Earnings up to 100 basis points above the allowed return on equity established in this proceeding will be shared 50/50 between ratepayers and the Company. Earnings of more than 100 basis points above the allowed return will be shared 75/25 between ratepayers and the Company. Ex. NGrid-15, Attachment NG-PCC-5 at 231; NGrid Response to Commission Record Request No. 24.

Company Position. The Company arrived at its proposed return on equity by measuring the cost of equity of a proxy group of seven natural gas companies using four methods: discounted cash flow ("DCF"), risk premium analysis ("RP"), capital asset pricing model ("CAPM"), and comparable earnings approach ("CE"). Ex. NGrid-8 at 5 (Moul).

The DCF model measures the value of an asset as the present value of future expected cash flows discounted at the appropriate risk-adjusted rate of return. At its simplest, the DCF return on common stocks consists of a current dividend yield and future price

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[3] Commissioner Bray dissents from this portion of the Decision and would adopt the Division's position for reasons stated on the record at the November 24, 2008 Open Meeting. Tr. 11/24/08 at 107.

[4] Based on projected cost of short-term debt of 2.58% vs. the Company's projected short-term debt cost of 4.59%. Tr. at 8/27/08 at 156.

[5] The Division proposed a cost of equity of 9.50% if its recommended capital structure were not used. Division Post-Hearing Reply at 2; Ex. DIV-5 at 4 and Schedules JAR 2 and 7.

appreciation of the investment. The DCF methodology requires the use of an expected dividend yield to establish an investor-required cost of equity. The adjusted dividend yield for the Company's proxy group was 3.86%. The Company's expert calculated a growth rate of 5.25%, a 0.54% upward leverage adjustment, and a 0.19% upward adjustment for flotation costs. Ex. NGrid-8 at 22-38 (Moul).

Under the risk premium approach, the cost of equity is determined by corporate bond yields plus a premium to account for the higher risk of equity compared to debt. The Company's expert concluded that a 6% yield on A-rated public utility bonds represents a reasonable yield expectation, and that 5.25% is a reasonable common equity risk premium. Ex. NGrid-8 at 38-43 (Moul).

The CAPM methodology uses the yield on a risk-free interest bearing obligation plus a rate of return that is proportional to the systematic risk of an investment. To compute the cost of equity using the CAPM method, three components are needed: a risk free rate of return, the beta measure of systematic risk, and the market risk premium derived from the total return on the market of equities reduced by the risk-free rate of return. The CAPM also takes into account the size of the company or portfolio for which the calculation is performed. The Company's expert calculated a 4.75% risk free rate of return, a leverage adjusted beta of 1.02, a market premium of 7.39% and a size adjustment of .97% to arrive at a CAPM return of 13.45%. Ex. NGrid-8 at 44-49 (Moul).

The Comparable Earnings approach looks at the returns realized by unregulated companies with risks that are comparable to regulated public utilities. One method involves selecting another industry or industries with comparable risks to a public utility, and then using the results for all companies in that industry as a benchmark. A second method involves

selecting parameters that represent similar risk traits for the public utility and unregulated comparables. The Company's expert selected comparable unregulated companies with six categories of comparability designed to reflect the risk of natural gas utilities. Under the Company's CE approach, the cost of equity was 13.90%. *Id.* Ex. NGrid-8 at 49-53 (Moul).

The average return of the Company's DCF, RP and CAPM models was 11.58%, which the Company adjusted to arrive at its proposed return of 11.50%. NGrid Post-Hearing Mem. at 12; Ex. NGrid-8 (Moul Pre-Filed Direct Testimony) at 7.

The Division's proposed rate of return is inordinately low for several reasons. First, the Division expert's DCF model uses the "retention growth rate" method, which requires an assumption of the return on book common equity for a proxy group. Ex. NGrid-9 at 22-23; Tr. 9/12/08 at 22-24. The Division's expert selected 12% for his key input value, which was the second lowest value in his data set of 10 values. *Id.* This approach introduced a "significant downward bias" causing the DCF results to be biased and unreasonably low. *Id.* To be valid, the Division's expert should have selected a balanced approach using a measure of central tendency, such as an average of the values, the median or a midpoint. Tr. 9/12/08 at 22-24. A balanced approach would have resulted in a higher value comparable to the Company's calculation (such as 10.25%, 10.03% and 10.68% depending on the choice of central tendency measure). *Id.*

Second, the Division's rate of return on common equity is significantly lower than almost any other utility for which a rate of return has been set in the most recent reported rate cases, according to information submitted by both the Company and the Division. *Id.* at 5; Ex. DIV-31. According to the Company's data, the average rate of return on common equity for natural gas utilities was 10.27% in the period October 1, 2006 through August 31, 2007. Ex.

NGrid-9 at 5 (Public Utility News, dated December 28, 2007). According to the Division's data, the average rate of return on common equity for natural gas utilities was 10.24% in calendar year 2007 and 10.35% for the first two quarters of 2008. Ex. DIV-31 (Regulatory Research Associates, dated July 2, 2008).

Third, the Division's rate of return fails to take adequate account of volatility in the capital markets and turmoil in the credit markets. The record shows that the cost of common equity has increased as a result of the global financial crisis because of a large increase in the risk premium which is currently estimated to be a 50 to 100 basis point increase in the cost of equity capital. Ex. NGrid-9 at 6-8; Tr. 10/22/08 at 21-22, 66-67. The Company is facing a significant new challenge in terms of assuring investors that their capital is safe with the Company. Ex. DIV-69. There can be no dispute that the Company will be faced with market realities in financing its operations following the Commission's rate case decision, and therefore, these realities need to be considered in the final result.

Lastly, the Division's expert failed to provide any record support for his 45 basis point adjustment to the cost of common equity to account for the higher financial risk associated with this proposal to set rates based on National Grid plc's lower common equity ratio. The Company demonstrated that rather than making an arbitrary adjustment, there are objective methods widely accepted in the financial literature that can be used to quantify the impact of a lower equity ratio on the cost of common equity. Ex. NGrid-9 at 37. By applying these methods, the Company demonstrated that, if the Commission sets rates based on National Grid plc's equity ratio of 37.77%, rather than the Company's proposed 47.71% ratio, the return on equity decided in this proceeding should be adjusted upwards by 98 basis points not 45 basis points. *Id.* at 3.

Division Position. The Division based its recommendation on the DCF method, applied to a comparative group of natural gas utilities. Ex. DIV-5 at 10 and Schedule JAR 3 (Rothschild). The Division's expert also presented a CAPM analysis to support his conclusion. Ex. DIV-5 at 24 (Rothschild). The Division disputed the Company expert's DCF methodology because it added a 0.54% upward leverage adjustment, and a 0.19% upward adjustment for flotation costs. The Division presented testimony that these adjustments are contrary to basic finance principles, and incorporate earnings per share growth rates that are not reflective of long term sustainable growth required for the constant growth form of the DCF analysis. Ex. DIV-5 at 57 (Rothschild). The Division also argued that the Company's risk premium analysis is inconsistent with Commission precedent, Ex. DIV-5 at 58-63 (Rothschild), and that the Company's CAPM analysis is flawed. Among the errors in the Company's CAPM analysis, (1) it improperly uses the arithmetic average, (2) it uses short term analyst forecasts as a proxy for long term sustainable growth, (3) it uses Value Line's five-year projection of total returns on the stock market as if it were intended to be a reflection of investor expectations when, in fact, Value Line has no such intention, and (4) it improperly inflates the beta as applied to the risk premium. Ex. DIV-5 at 64 (Rothschild).

Commission Decision. The Commission has historically expressed a preference for the use of the DCF methodology to determine return on equity. *See, e.g., In re Valley Gas Co. & Bristol & Warren Gas Co.*, Docket No. 2276, Order No. 14834, at 12 (1995) ("this Commission has consistently stated its preference for the use of the discounted cash flow (DCF) methodology"). Using the DCF methodology and a proxy group of companies, the Division's expert arrived at a 9.95% return. However, the record reflects that minor adjustments to the Division's DCF methodology would have produced a higher return. For example, the Division's

DCF expert used 12% as a key input value, which was the second lowest value in his data set of ten values for his proxy group. If he had used the average value of this data set his DCF result would have moved to 10.25%. Ex. NGrid -9 at 22-23; Tr. 9/12/08 at 22-24.

The Company arrived at its proposed 11.5% return on equity by averaging the results of three out of four return on equity calculations, and making upward adjustments to some of its calculations that were challenged by the Division. Ex. NGrid-8 (Moul Pre-Filed Direct Testimony) at 7-8. While the Company's expert proffered explanations for his blended approach, the Division presented evidence that alternate assumptions and calculations would significantly lower the Company expert's result. For example, the Division presented credible evidence that the Company's CAPM analysis, which produced a return on equity of 13.45%, contained a number of flaws. Ex. DIV-5 at 44-45 (Rothschild). The Division also presented testimony that the Company's use of a leverage adjustment and a flotation cost adjustment in its DCF calculation were inappropriate. Ex. DIV-5 at 57 (Rothschild). Excluding these adjustments would have reduced the Company's return on equity based on the DCF method to 9.11% from 9.84%, and reduced the Company's proposed blended rate of return accordingly. Ex. NGrid-8 (Moul Pre-filed Direct Testimony) at 7-8.

The Commission therefore finds that while the expert analyses presented by the Division and the Company are useful indicators of a reasonable range for a return on equity, neither is definitive. In arriving at this conclusion, the Commission notes that the Division's proposed return on equity is below – and the Company's above – recent average rates of return on common equity for other U.S. natural gas utilities. Evidence submitted by the Company, and not disputed by the Division, shows that the U.S. average return on equity for gas utilities is 10.27%. Approximately two thirds of U.S. gas utilities have been allowed returns on equity

between 10 and 10.9%. Tr. 8/27/08 at 23-24; Ex. NGrid 9 at 5 (Moul). Some of the other natural gas utilities with allowed returns in this range have decoupling mechanisms in place. Ex. NGrid-18 at 11 (Hevert); Tr. 9/10/08 116-123. The record reflects that while many utility commissions have not made explicit reductions to authorized return on equity on account of decoupling, there is evidence that in some proceedings the regulatory agency has found it appropriate to reduce the return on equity of a utility that has revenue decoupling. Ex. NGrid-18 at 26 (Hevert).

The Division argued that recent statements by the Company's chief executive officer to investors support a return on equity below 10%. For example, in October 2008 the chairman and CEO told investors that National Grid plc is an "extraordinarily low risk" company with very solid returns. Ex. DIV-70. Investors were further told that "[w]e are a very low risk business." Ex. DIV-69 at 6; Tr. 10/22/08 at 76. Without further evidence to show what "low risk" meant to the speaker making these statements, however, they have little probative value.

Based on all of the evidence presented, the Commission finds that 10.5% is a reasonable return on equity for the Company's Rhode Island operations. This return on equity is comparable to the U.S. average for natural gas utilities, with a slight upward adjustment in recognition of the market turmoil that has occurred since the Company submitted its filing in April 2008. Ex. NGrid 9 at 14-24 (Moul Rebuttal) (recent economic conditions which the Company believes will increase the cost of equity capital). The Commission has the discretion to grant a return on equity that brings the Company in line with other comparable utilities. *See Narragansett Electric Co. v. Harsch*, 117 R.I. 395, 368 A.2d 1194 (1977) (utility may be granted rate of return sufficient to bring its return in line with those currently achieved in the same region by entities with similar risks). A return on equity of 10.5%, when applied to the Company's

approved rate base, should enable the Company to serve its customers effectively and adequately compensate investors for risks assumed.[6]

3. Size of Rate Base.

The Company proposed a rate base of $285,241,458. Ex. NGrid-3 at 44 and Attachment NG-MDL-1 at 24. The Company's proposal was based on forecasted additions to plant in service of $36,679,000 in the twelve months ending September 30, 2008, and $60,780,000 in the twelve months ending September 30, 2009. Ex. NGrid-3 at 42-44 and Attachment MDL 1, p. 26 of 33. The Division proposed reducing average rate year plant in service by $10,259,000, resulting in a net rate base reduction of $9,980,000 to $275,261,000. NGrid Post-Hearing Mem. at 17.

Company Position. The Company argues that the budgeted expenditures for plant additions will be incurred. A lag in contractor billing is responsible for actual spending in the early months of the period running below budget. Tr. 9/9/08, at 9-10, 12 (Fleck). The Company further argues that the Division's adjustment incorrectly assumes that spending on additions is linear. The Company offers to update its responses to Data Requests DIV 1-2 and DIV 13-4 through October 2008 and represents that they would show that the gap between budgeted and actual spending is narrowing. NGrid Post-Hearing Reply at 20. The Company also represents that it does not object to an adjustment in the rate year end plant in service amount if the projected capital spending does not occur. *Id.* at 19.

Division Position. The Division reduced the proposed rate base after reviewing the Company's actual capital expenditures for the period October 2007 through March 2008, and determining that they were only $14.36 million, or 19.4% below budget. Ex. DIV-8 (Data

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[6] Commissioner Bray dissents from this portion of the Commission's decision and would adopt the Division's position for reasons stated on the record at the November 24, 2008 Open Meeting. Tr. 11/24/08 at 110.

Request DIV 1-2). Based on those actual expenditures, the Division asserts that the Company has overstated its forecasted capital additions in the 12 months ending September 30, 2008 by $5,282,000, and overstated forecasted capital additions for the twelve months ending September 30, 2009 by $9,954,000.

Commission Decision. At the hearings, the Company presented evidence that the budgeted expenditures will be incurred. Tr. 9/9/08 at 9-10 (Fleck). The Company's testimony that a lag in contractor billing is responsible for actual spending in the early months of the period running below budget was not rebutted. Tr. 9/9/08 at 9-10, 12 (Fleck). The Company also represented to the Commission that if it were to update its responses to Data Requests DIV 1-2 and DIV 13-4 through October 2008, it would show that the gap between budgeted and actual spending is narrowing. NGrid Post-Hearing Reply at 20; Ex. DIV-52. In addition, the Company represented to the Commission that it would not object to an adjustment in the rate year end plant in service amount if the projected capital spending does not occur. *Id.* at 19.

The Commission finds that the Division's position, while reasonable based on the information made available by the Company prior to the hearings, does not account for the lag in contractor billings in the early months of the measuring period, or the non-linear rate of spending on plant additions. The Commission therefore approves the Company's proposed rate year rate base. In the event that the projected capital spending does not occur prior to the end of the rate year, the Company shall notify the Division and make an appropriate adjustment to reflect the actual lower amount of actual plant in service.

B. Operating Expenses (Cost of Service).

1. Health Care Costs.

The Company proposed rate year medical and dental costs of $4,614,000, a 21.4% increase over the test year expense. Ex. NGrid-3 at 18 and Attachment NG-MDL-1 at 8

(Laflamme); Tr. 8/27/08 at 39. The Division reduced rate year health care costs by $907,456 based on seven months of actual data, which suggested that costs would be less than proposed by the Company. Ex. DIV-1 at 5-7 (Effron). The Company disagreed that seven months of data are adequate to calculate costs, but did not challenge the reduction. Tr. 9/8/08 at 84-85 , 101-102 (Laflamme); NGrid Post-Hearing Mem. at 20. The Commission approves the reduction of $907,456.

2. **FAS 112 Expense.**

FAS 112 relates to post-employment benefits other than pension, such as short term and long term disability benefits and health care costs associated with employees, their dependants and beneficiaries. The Company initially proposed an expense of $912,846. The Division challenged this amount on the grounds that some or all of the proposed expense appeared to be a "catch-up" of non-recurring prior year costs not appropriate to include in the rate base. Ex. DIV-2 at 2 (Effron); Ex. DIV-28 (Data Request DIV 13-2); Commission Record Request No. 5; Tr. 9/8/08 at 89-92, 94-96. At the hearings, the Company developed testimony indicating that a portion of its proposed FAS 112 expense is non-recurring. Tr. 9/8/08 at 91 (Laflamme). The Company revised its proposed FAS 112 expense from $912,846 to $740,000. Tr. 9/8/08 at 89-92, 94-96; Ex. NGrid-4, Attachment NG-MDL Rebuttal 2 at 3; Ex. NGrid-21 (NGrid Response to Data Request DIV 13-3).

The Division's witness agreed that FAS 112 expense is appropriate to include in the revenue requirement "assuming it's a normal, ongoing level of expense." Tr. 9/8/08 at 180 (Effron). The Division states that the proposed downward adjustment to $740,000 "is not unreasonable." Division Post-Hearing Mem. at 21.

The Commission finds that FAS 112 expense is a normal, recurring expense associated with employee benefits, and that the Company has removed any "catch-up" amount

resulting from an error in recording the Company's FAS 112 expense following the Southern Union transaction. The Commission further finds that the Company's estimated FAS 112 expense for FY 2009 is $740,000, which is representative of the expense level that the Company will experience on a going-forward basis.

3. Synergy Savings – Southern Union Merger.

In August 2006, National Grid acquired the Rhode Island operations of New England Gas company from Southern Union. The Company proposed adding $1,054,609 to its cost of service revenue requirement in this docket to reflect the Company's 50 percent share of asserted synergy savings from the merger. The adjustment included $896,971 of shared savings and $157,638 for amortization of costs to achieve. Ex. NGrid-3, Attachment NG-MDL-1; Ex. NGrid-4 at 13 and Attachment NG-MDL Rebuttal 4. The Company proposed including this amount in rates for 10 years. *Id.*

Company Position. The Company measured its proposed merger synergy savings by comparing three categories of corporate expense: employee compensation, administrative and general expense, and corporate office expense. The Company's approach was to look at changes in these categories because the merger did not combine operations. Pre-merger costs were measured during the year ending June 30, 2006. Post-merger costs were measured during the test year, ending September 30, 2007. Ex. NGrid-4, Attachment MDL Rebuttal-4 (calculating total demonstrated savings of $1,951,580); Tr. 9/8/08 at 75-76 (Laflamme).

The Company argues that using the Division's benchmark period (the year ending June 30, 2003) to calculate synergy savings is not appropriate because it does not account for three years of cost increases or decreases before National Grid acquired the business in 2006, for gas sales declines after 2003, or a significant increase in rate base from infrastructure investments. Tr. 9/8/08 at 104-107; Ex. NGrid-4 at 11-12 (Laflamme Rebuttal). The Company

contends that "the record is clear that cost levels in discrete cost categories are reduced from prior levels" after the merger. NGrid Post-Hearing Mem. at 25. The Company disputes that expenses in the year ending June 30, 2006 were unusually high, and asserts that in any event the unusual expenses cited by the Division were in categories (distribution maintenance and uncollectables expense) not relevant to the Company's merger synergy calculation. *Id.* at 26-28, 32-33. The revenue requirement approved in Docket No. 3401 was based in part on a review of anticipated consolidation savings in specific cost categories, and the Docket No. 3401 savings proof was not intended to quantify underlying merger synergies, but only to determine whether shareholders would be entitled to continue to claim 50% of those synergies in a future base rate case. *Id.* at 29-32.

Division Position. The Division argues that the Commission has never reviewed Southern Union's expenses incurred in the year ending June 30, 2006 to determine if they are appropriate for rate-making purposes, and that therefore those expenses should not be used as a benchmark for measuring synergy savings. Division Post-Hearing Mem. at 29; Tr. 9/8/08 at 168-171 (Effron). The Division also expresses reservations about the Company's approach of selecting only certain expense categories for purposes of calculating savings, on the grounds that it was more likely to present the merger in a favorable light than a broad measure of the cost of service. Division Post-Hearing Mem. at 27-28; Tr. 9/8/08 at 103. The Division asserts that the Commission has already approved a method of measuring synergy savings achieved by the former New England Gas Company that broadly measures changes in the cost of service. Using this method, no synergy savings have been demonstrated because the normalized post-acquisition cost of service exceeds the inflation adjusted and normalized benchmark cost of

service for the acquired Rhode Island natural gas operations established in Docket No. 3401 by about $12.4 million. Ex. DIV-1 at 14 (Effron Direct) and Schedule DJE-4.1.

Commission Decision. The Commission in the past has allowed a 50/50 sharing of net merger savings between ratepayers and the Company. The Company realizes its share of the savings by adding them to the cost of service. *See, e.g., New England Gas Company*, Docket No. 3401, Order No. 17381 (2002). The rationale for allowing sharing of synergy savings is that the savings would not exist for customers without shareholders being willing to incur the costs of the merger. Synergy savings are only appropriate, however, when there is an adequate basis for establishing that the savings have been achieved.

The Commission finds that the Company's method of comparing post-transaction cost of service to a pre-transaction cost of service for the twelve months ended June 30, 2006 is not appropriate in this case. The Company's expenses for that pre-transaction period were never approved for inclusion in the base rates, and might not be indicative of a reasonable, normal level of ongoing expenses. The Division presented testimony suggesting that at least some expenses incurred by the Company in its benchmark period ending June 30, 2006 may have been excessive. Tr. 9/8/08 at 170 (Effron). Other evidence supported the Division's position that selecting only certain expense categories to measure synergy savings could present the merger in a more favorable light than a broad measure of expenses: a Company witness testified that an alternative calculation based on a broader measure of expenses would reduce the synergy savings proposed by the Company by approximately $250,000. Ex. NGrid-23 and Tr. 9/8/08 at 111-115.

The Company has the burden of presenting sufficient evidence in support of a requested rate increase. R.I.G.L. § 39-3-12 ("At any hearing involving any proposed increase in any rate, toll or charge, the burden of proof to show that the increase is necessary in order to

obtain a reasonable compensation for the service rendered shall be upon the public utility."). In the absence of additional evidence from the Company supporting the reasonableness of its expenses during its benchmark period, the Commission finds that no National Grid/Southern Union merger synergy savings have been shown.

4. Synergy Savings – KeySpan Merger.

In August 2007, National Grid completed a merger with KeySpan Corporation, resulting in a combined organization serving approximately 3 million natural gas customers in four states. The Company proposed reducing the base rate revenue requirement by $2.45 million to reflect the ratepayer half of anticipated synergy savings from National Grid's acquisition of KeySpan, net of the annual amortization of the cost to achieve. Ex. NGrid-3 at 39-40 (Laflamme Direct); Ex. NGrid-4 at 14-15 (Laflamme Rebuttal). The Company proposed this reduction although it does not expect the full amount of savings to be achieved until the fourth year after the merger.[7] The Company also proposed that it should be allowed to fix its share of the synergy savings in future rate proceedings at the same $2.45 million. The Division accepted the up front synergy savings for ratepayers, but initially proposed that any future synergy savings for the Company be subject to proof. The Company objected to giving the ratepayers up front credit for synergy savings not yet achieved in the rate year ($1.2 million of the $2.45 million), while subjecting the Company to a savings proof. Ex. NGrid-4 at 39 (Laflamme Rebuttal).

At the hearings, the Company and the Division stipulated that merger savings totaling $6.4 million are projected to result from the National Grid/KeySpan transaction, and that the annual amortization of the cost to achieve the merger savings is $1.5 million. The Company and the Division also stipulated that $2.45 million should be included in the base rate revenue

[7] Ratepayers' 50% share of net synergies to be achieved during the rate year is $1.3 million. Ex. NGrid 4 at 14-15 and Attachment MDL Rebuttal 5.

requirement as a credit, to reflect the ratepayers' 50% share of the projected merger synergies net of costs to achieve. Tr. 9/8/08 at 71-72 (Laflamme). The stipulation further provides that the Company will be allowed to include its $2.45 million share of projected merger synergies as a line item in the cost of service in any rate case filed within five years after the Commission's order in this case. Tr. 9/8/08 at 70-73 (Laflamme). In any rate case filed after five years but within ten years, the Company's share of synergy savings from the KeySpan merger will be subject to a savings proof based on a comparison of pre-merger total O&M expense (escalated for inflation) to total rate year O&M proposed in the rate case. The pre-merger total operation and maintenance expenses for this calculation will be the adjusted per book expenses for the twelve months ended September 30, 2007 as reflected in this proceeding. The Company will for ten years be allowed to reflect its share of savings in annual earnings reports filed with the Commission for earnings sharing purposes. The Commission finds that the stipulated synergy savings will provide a direct benefit to ratepayers, and that putting off including the ratepayer share of KeySpan merger synergy savings in the rate base until a future rate case is not in the best interest of the Company's Rhode Island customers. The Commission approves the stipulation.[8]

The Company requested that the Commission allow it to create a regulatory asset in accordance with FAS 71 to account for the levelized amortization costs to achieve over a ten year period to be included in its cost of service. *Id.,* NGrid Post-Hearing Mem. at 36. The Commission finds that a regulatory asset pursuant to FAS 71 is a reasonable step ancillary to the approval of the synergy savings. The Commission approves this request.

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[8] Commissioner Holbrook dissents from this portion of the Commission's decision and would require that the synergy savings be determined in a separate docket for reasons stated on the record at the November 24, 2008 Open Meeting. Tr. 11/24/08 at 119.

5. Gas Marketing Program.

The Company proposed to establish a ratepayer-funded Gas Marketing Program and to include marketing program costs of $1,377,000 in the base revenue requirement: $698,798 for customer rebates and incentives, $528,000 for customer outreach and communication, and $150,000 for program administration. Ex. NGrid-6 at 25-26 (Mongan Direct); Ex. DIV-8 (Data Request DIV 1-20). The Division objected, and proposed an allowed marketing expense of $148,000.

Company Position. The Company states that it is proposing a Gas Marketing Program that will (1) expand the use of natural gas as a cleaner-burning fuel than heating oil alternatives, (2) maintain the overall throughput of the system so that the cost of the system is not carried by fewer and fewer units, and (3) operate at no cost to the system because revenues received from new customers will exceed the cost to add them. NGrid Opening Statement at 30; NGrid Post-Hearing Mem. at 37, 42. The proposed program will target residential and C&I customers located on the existing distribution system who do not use gas, or use only limited quantities (*i.e.*, residential non-heating customers). Ex. NGrid-6 at 4-5 (Mongan Direct). The Company projects 1,950 incremental residential conversions from the program in 2008 and has incorporated approximately $900,000 of revenues from these anticipated new customers in its revenue requirement calculations, as well as $550,000 of incremental rate base expense. Ex. NGrid-7 at 9 (Mongan Rebuttal); Ex. NGrid-6 Attachment SPM-1; Tr. 8/27/08 at 46.

In the Company's view, the Gas Marketing Program is needed to offset customers' up front cost of converting from oil to natural gas. The Company believes that this incremental investment poses a significant obstacle for many customers, regardless of any price differential between oil and natural gas. Ex. NGrid-6 at 10-11; Ex. DIV-17 (Data Request DIV 8-7); NGrid Post-Hearing Mem. at 39-40. The Company anticipates a 400% increase in Rhode

Island oil to gas conversions through the end of fiscal year 2009, resulting from the Gas Marketing Program and the oil/gas price differential. Ex. COMM-1 (Data Request COMM 1-23). This increase is much larger than in the Company's other jurisdictions where rate-funded gas marketing programs have existed for some time. *Id.*

The Company disputes that passing equipment discounts through to is customers, or offering equipment rebates, is discriminatory or anticompetitive. The record shows that the Company is purchasing of equipment in bulk from manufacturers who were the successful bidders in a competitive solicitation and is passing the competitive price made available by the manufacturer to all customers who are interested in procuring their furnace or boiler through the Company. Ex. DIV-3 at 28. The Company is not making any profit on the sale of equipment, nor is it adding any type of markup. *Id.* Moreover, all converting customers are eligible for the equipment rebate, regardless of whether they purchase their equipment through the Gas Marketing Program, or through a third-party plumbing and heating contractor. *Id.* Thus, the Company is purchasing the equipment at a market price following a competitive solicitation; is providing that equipment to converting customers at cost, and is offering equipment rebates to all converting customers on a non-discriminatory basis.

The Company also disputes that its ValuePlus Installer program improperly benefits its unregulated affiliate, National Grid Energy Services ("NGES"). The record shows that the only contact that the Company would have with NGES is through the ValuePlus Installer ("VPI") Program, which occurs because NGES is allowed to participate on the same basis as all other pluming and heating contractors. *Id.* The record shows that out of all the conversions completed through the program, approximately 30 percent utilize a referral through the VPI Program. *Id.* The record also shows that NGES handles only a small percentage (5% on

average) of the total conversions completed in any jurisdiction in which the company conducts the Gas Marketing Program. Thus, there is no record support for the conclusion that the Company's unregulated affiliate would be favored or would unduly benefit from the existence of the Gas Marketing Program.

The Company's internal rate of return calculation for new customers added through the Gas Marketing Program demonstrates that the program will benefit ratepayers by generating returns from new customers that exceed the Company's allowed return on equity. Ex. NGrid-6 at 23-24 (Mongan). The Company produced an internal rate of return calculation demonstrating that the addition of new residential customers through the Gas Marketing Program would produce a rate of return of approximately 14.8 percent, while new C&I customers will produce a rate of return of approximately 21.4 percent. *Id.* at 28. This calculation is significant because it means that, in this case, the Commission will aim to design rates to recover the Company's allowed return on equity but customer additions completed through the program will produce a rate of return in excess of that amount. Ex. NGrid-6 at 21-22 (Mongan). Since the Company is proposing to implement an earnings sharing mechanism to share earnings in excess of the allowed rate of return, customer additions resulting from the program will inure to the direct benefit of existing customers, who are credited with 50 percent of earnings in excess of return on equity and 75 percent of incremental earnings greater than 100 basis points above the allowed 10.5% return on equity.

The Company maintains that the Gas Marketing Program is not prohibited by Rhode Island law because it is designed to encourage gas conversions by (1) extolling the efficiency of gas furnaces and other major home appliances, (2) raising customer awareness regarding the amount of money consumers would save by using newer, efficient equipment

models, (3) providing informational materials that encourage the use of newer and more efficient gas appliances, and (4) encouraging conservation rather than merely promoting the use of gas. NGrid Response to Legal Memorandum on Gas Marketing Program at 15. Even assuming that the customer communications under the Gas Marketing Program are promotional, and therefore prohibited by R.I.G.L. § 39-2-1.2, rebates, discounts and staffing are not direct or indirect costs of advertising, and should be allowed. *Id.* at 16.

Even institutional and branding costs may be allowable, if there is a demonstrated customer benefit. NGrid Response to Legal Memorandum on Gas Marketing Program at 6. The Company has demonstrated that the Gas Marketing Program will directly benefit customers in both the near and long-term. *Id.* at 19, 23-24.

Division Position. The Division argues that the incremental growth in revenues that the Company estimates will arise from the Gas Marketing Program will still be achieved without it. Data for the first eight months of 2008 show 1,617 conversions and upgrades, a nearly 250% increase over the corresponding period in 2007. Ex. DIV-11, Response to Commission Data Request 3-8. Conversions in the first eight months of 2008 exceeded the annual conversions that the Gas Marketing Program seeks to achieve. Ex. NGrid-6, Attachment NG-SPM-1. The expense of the Gas Marketing Program is not necessary. The Company should be permitted to spend only an amount equal to the planned spending of Rhode Island oil dealers, $148,000. Ex. DIV-3 at 27 (Oliver).

The Division disputes the argument that the cost of adding the new customers targeted by the Gas Marketing Program exceeds the incremental revenue. The Company has focused its marketing effort on customers located near existing distribution mains. Because distribution mains represent the largest element of the Company's rate base, new customers who

do not require additions to distribution mains can be added to the system at less than the average cost on which rates will be based. Division Post-Hearing Mem. at 22.

The Division also argues that the Gas Marketing Program would result in ratepayer funds being used to benefit the Company's unregulated affiliate, National Grid Energy Services. National Grid Energy Services performs oil to gas conversions in competition with other plumbing and heating contractors. Tr. 10/20/08 at 201-04 (Mongan). The Company's practice is to refer customer conversion inquiries to contractors on its Value Plus Installer list, including National Grid Energy Services; therefore, increasing the number of oil to gas conversions directly benefits National Grid Energy Services along with other conversion contractors. To date, National Grid Energy Services has performed only a small percentage of all residential conversions in Rhode Island. The Division asserts that over time the unregulated affiliate will become the dominant beneficiary of the marketing expenses being paid by ratepayers.

The Division also argues that the Company launched the Gas Marketing Program with its own funds earlier this year, and is likely to continue it even without explicit cost recovery through rates. Current economic conditions argue against an increased rate burden for an unnecessary program. Furthermore, the program arguably violates R.I.G.L. § 39-2-1.2 because it is designed to promote the consumption of natural gas. Division Post-Hearing Mem. at 25-26.

Attorney General Position. The Rhode Island Attorney General states that the proposed Gas Marketing Program is prohibited by G.L. § 39-2-1.2(a), which does not allow expenses in the Company's rate base for "advertising, either direct or indirect, which promotes the use of its product or service, or is designed to promote the public image of the industry."

Advertising under the statute includes all forms of promotional media, as well as promotional activities including discounts, rebates, and sales administration. The Commission has disallowed promotional, goodwill and institutional advertising expenses, including labor expenses, in prior dockets. RIAG Post-Hearing Mem. at 2-7.

The Gas Marketing Program does not qualify for the statutory exemption allowing advertising "informational or educational in nature, which is designed to promote public safety and conservation of the public utility's product or service." R.I.G.L. § 39-1-1.2(a). Each component of the program promotes use of natural gas. RIAG Post-Hearing Mem. at 9-13; Ex. NGrid 6; Ex. AG-3; Tr. 10/23/08 at 163-173 (Oliver); Tr. 10/20/08 at 194-95 (Mongan).

The customer outreach and education component of the Program consists of a concerted marketing effort to convince a target set of potential customers to convert to natural gas over their existing "energy choice." Ex. NGrid-6 at 8-9, 11. Through direct mailings, radio, and visual media, etc., the Company represents to customers that they can "save money" (because gas is more "efficient" than oil) and "save space" (by "saying good-bye" to your old oil tank and the "soot, fumes, and sulfur dioxide" of oil). *See, e.g.* Ex. AG-3 at 3, 12, 18, 20, 22. The Company also represents that customers can "find help" locating a "qualified" contractor through the Company's VPI Program and earn "valuable rebates . . . up to $1,500 on heating equipment," a $1,500 discount "that'll make your [the customer's] wallet happier too." *See, e.g.,* Ex. AG-3 at 11-12, 15-16, 18. The stated purpose of these communications is to "identify potential conversion candidates" and to "pass those contacts on to local plumbing and heating contractors" participating in the Company's VPI program. Ex. NGrid-6 at 15-16.

The Program's customer outreach and education component is not tailored merely to inform customers about the benefits of natural gas in terms of efficiency and conservation.

Rather, the component functions to identify, and then to steer target customers who do not have relationships with contractors towards contractors who will convert their system(s) to natural gas (*e.g.*, typically an "on-main conversion or low-use upgrade") from the customers' existing energy sources. Ex. NGrid-6 at 16. The component, therefore, is purely promotional in nature.

Substantially all of the testimony in the record supports this conclusion. Mr. Mongan acknowledged that the direct mail materials that the Company forwarded to its customers in connection with the Program in late 2007 and early 2008 promote natural gas over oil in multiple ways: (i) by intimating that customers waste .30 of every dollar in oil heat; (ii) by invoking fears that with oil comes the ever-present worry of a leaky tank; (iii) by implying that purchasing natural gas (rather than oil) is more patriotic because 97.3% of it as opposed to 56% for oil "comes from North America;" and (iv) by stating that burning oil inevitably produces "fumes" and "greenhouse gases" that are not associated with natural gas. Tr. 10/20/08 at 195-197.

The second component of the Program – installation support and associated labor ($150,000) – violates § 39-2-1.2(a) for a similar reason. The VPI Program is a "contractor-referral system" that seeks "to facilitate the Company's efforts to increase system utilization in a cost-effective manner through low-use upgrades and on-main conversions," Ex. NGrid-6 at 17, and specifically, is designated to "create a high level of customer satisfaction and convenience," facilitating the Company's effort to "increase system utilization." Ex. NGrid-6 at 17. The principal aim of the VPI Program and associated incremental labor, is to promote natural gas over customers' existing energy sources and to promote the public image of natural gas.

The record evidence supports this conclusion. Mr. Oliver testified that in his expert opinion the VPI Program is promotional. Tr. 10/23/08 at 173. Mr. Mongan confirmed

that the Company had engaged an "in bound inquiry rep" as well as an "inside sales rep" to handle all conversion related calls. Tr. 10/20/08 at 194. Customers that require contractors are steered to the VPI network. Tr. 10/20/08 at 194-195. This serves the promotional aim of the gas marketing program: to facilitate customer conversions from other energy sources to natural gas. Tr. 10/20/08 at 194-195.

The equipment discount and rebate components of the Program also serve to promote the use of gas over customers' existing sources of energy. Ex. NGrid-6 at 18-19. Under the third component of the Program (equipment discounts), "purchased equipment is offered to customers . . . at a price that reflects both the Company's bulk-purchase discount and also a further discount made available through the [Program] to enable customer conversions to gas service." Ex. NGrid-6 at 18. "Because the cost of gas conversion can be higher than other fuel options available to the customer, the combination of the bulk purchasing discount and the program discount provide a valuable incentive to customers" to enable them to switch to gas service from their existing energy source. Ex. NGrid-6 at 18.

The same is true for equipment rebates – the fourth component of the Program. "Customers who would prefer to purchase gas-heating equipment from a manufacturer that is not part of the Company's bulk purchasing program" are "eligible for a rebate of equal value to the program discount offered on equipment purchased by the Company from its manufacturing suppliers." Ex. NGrid-6 at 18. This ensures that customers are able to obtain the same program incentive – the elimination of "incremental costs" – that "must be overcome in order to motivate new gas conversions." Ex. NGrid-6 at 19.

Most, if not all of the evidence on the record, corroborates the promotional nature of equipment discounts and rebates. Mr. Oliver testified that in his expert opinion, the rebates and discounts associated with the Program are promotional in nature:

> Q. Do you believe that those other components, . . . the rebates and discounts, that those have a characteristic that would advance one energy source over another?
>
> A. They tend to, yes.

Tr. 10/23/08 at 173. The equipment rebates and discounts, moreover, are directly marketed to customers in the customer outreach and education component of the Program. Tr. 10/20/08 at 197. Without the rebates and discounts, the other promotional components of the Program would not, and could not, function. Tr. 10/20/08 at 247-48.

The Company has not provided any analysis of the internal rate of return of the Gas Marketing Program in the absence of the price differential between oil and gas. The record supports the conclusion that the increase in conversions is the result of this price differential, not the Company's marketing program. The customer outreach and education component of the Program commenced in the last quarter of 2007. Ex. AG-3 at 1. For the first quarter of 2008, the Company completed 628 residential conversions – which the Company concedes "is a greater number of conversions than experienced in the past for the same period." Ex. NGrid-7 at 9. The Company projects 1,950 incremental residential conversions in 2008, all the while conceding that during this time period natural gas has enjoyed and continues to enjoy a substantial price differential advantage as compared with oil – a differential which "is currently motivating some customers to commence the conversion process . . . ." Ex. NGrid-7 at 11. The Company concedes, moreover, that many (but not all of) the conversions to date can be attributed to the cost differential and not the Program. Ex. NGrid-7 at 10; *see also* Tr. 10/23/08 at 160-61 (Oliver) (price differentials "very strongly suggest that not only today but in the long

run heating with natural gas would be a preferred alternative"). Therefore there is no clear evidence to show that the program will provide a direct ratepayer benefit, which in some other jurisdictions (but not Rhode Island) might justify the expense. RIAG Post-Hearing Mem. at 14-16.

The proposed program would be detrimental to ratepayers because (1) they would be paying the cost of identifying conversion opportunities for the Company's unregulated affiliate, (2) they would be funding the inside inquiry and sales representative activities that benefit the unregulated affiliate, and (3) they would pay for equipment discounts and rebates afforded to customers of the unregulated affiliate, without any contribution from the unregulated affiliate. RIAG Post-Hearing Mem. at 16-19.

Commission Decision. Regardless of the alleged economic, environmental or customer benefits of the proposed Gas Marketing Program, it must comply with Rhode Island law. In Rhode Island, base rates may not include a utility's expenses for "advertising, either direct or indirect, which promotes the use of its product or service, or is designed to promote the public image of the industry." R.I.G.L. § 39-2-1.2(a). The Commission has disallowed promotional, goodwill and institutional advertising expenses, including promotion-related labor expenses, in prior dockets. *See, e.g., Tariff Filing Made by the Providence Gas Company on February 16, 1995*, Docket No. 2286, Order No. 14589 (1995) (allowing informational expenses but disallowing promotional, goodwill and advertising expenses of $457,000); *Valley Gas Co. v. Burke*, 518 A.2d 1363, 1366 (R.I. 1986) (upholding Commission decision to approve informational advertising expenses and deny promotional advertising expenses). Advertising expenses are allowable only for advertising that is "informational or educational in nature, which

is designed to promote public safety and conservation of the public utility's product or service." R.I.G.L. § 39-1-1.2(a).

The Commission finds that the evidence presented in this docket demonstrates that the Company's Gas Marketing Program promotes the use of natural gas, contrary to R.I.G.L. § 39-2-1.2(a). Company testimony expressly linked the marketing program to increased gas consumption by existing low-use customers or new customers near existing distribution lines. For example, one Company witness stated:

> The basic objective of the Company's Gas Marketing Program is to encourage cost-effective, increased system utilization through conversions of new and existing low-use customers to gas service.

Ex. NGrid-8 at 4 (Mongan Direct); *see also id.* at 13 ("the Gas Marketing Program is targeted at motivating conversions to gas service . . . ."). The record also reflects that the Gas Marketing Program will benefit the Company's unregulated affiliate, National Grid Energy Services, by generating sales leads that will be shared with National Grid Energy Services along with other contractors participating in the Value Plus Installer program. Tr. 10/20/08 at 199, 235-236 (Mongan).

The Company's arguments that the Gas Marketing Program should be allowed because it entails advertising "informational or educational in nature, which is designed to promote public safety and conservation of the public utility's product or service," R.I.G.L. § 39-1-1.2(a), are not persuasive. It is unusual for gas distribution companies to market conversions with ratepayer funds, Tr. 10/21/08 at 144 (Oliver), and the Commission sees no basis to extend the definition of "informational or educational" activities to include activities aimed primarily at adding new natural gas customers to the distribution system. The Company launched the program with its own funds earlier this year, Tr. 10/22/08 at 60-61 (Stavropoulos), and

anticipates that it will produce high internal rates of return. Tr. 10/20/08 at 142 (Mongan). Current economic conditions argue against an increased rate burden for marketing efforts that were sufficiently beneficial to the Company that they were initiated without a ratepayer contribution.

The Commission further finds that the incremental rate year sales that the Company has estimated will be produced by the Gas Marketing Program should not be eliminated. Data for the first eight months of 2008 show conversions up nearly 250% over the corresponding period in 2007. Ex. DIV-11, Response to Commission Data Request 3-8. The Division presented testimony that over time, natural gas will hold a significant price advantage over oil that will encourage conversions. Tr. 10/21/08 at 66-72; Ex. DIV-3 at 20-21 (Oliver). This evidence supports the conclusion that the Company's estimated sales growth from conversions will be achieved even without a ratepayer funded Gas Marketing Program.

6. Uncollectible Expense.

The Division proposed reducing the Company's uncollectible accounts receivable expense of $3,594,522 by 50% of the cost of the proposed low income discount, or $415,000, if the proposed low income discount were adopted by the Commission. The Division presented testimony linking the proposed discount to a reduction in uncollectible accounts. Ex. DIV-3 at 72 (Oliver) ("This recognizes that a large portion of the [low income] discount amounts would likely become future uncollectible accounts expenses in the absence of the offered discounts, and it shares the risks associated with the effectiveness of those discounts between the Company and its ratepayers.").

The Company does not gather information from which it can determine the actual uncollectible rate for low income customers. However, the Company disputed that any link exists and presented evidence that uncollectible accounts for electric service have increased

notwithstanding a low income discount for electric ratepayers. Ex. NGrid-4 at 8-9 (Laflamme Rebuttal); Tr. 9/8/08 at 98-101 (Laflamme).

At the hearings, the Division and the Company stipulated that in the event the Commission approved a low income discount (of any size), uncollectible expense would be reduced by $150,000. Tr. 9/11/08 at 175-176 (Czekanski); Division Post-Hearing Mem. at 30. The Commission approves the stipulated $150,000 reduction.

7. **Rate Case Expense.**

The Company proposed that rate case expenses for the Company, the Division and the Commission be allowed through base rates, amortized over three years. NGrid Post-Hearing Mem. at 45. The record reflects that that Company will incur rate case expenses totaling $884,481; the Division will incur rate case expenses totaling $113,075; and the Commission will incur rate case expenses of $350,887; for a total rate case expense of $1,348,443. NGrid Response to Commission Post-Hearing Data Request Set 1; Division Response to Commission Post-Hearing Data Request Set 1; Tr. 11/24/08 at 93-94. The Commission finds that rate case expenses are a necessary cost for the Company and recovery of reasonable rate case expenses is allowed through base rates under the Commission's precedent. The Commission further finds that the expenses of the Company, the Division and the Commission are reasonable in light of the scope, complexity and novel policy issues of this contested rate case, as reflected in the voluminous record and lengthy public hearings. The Company shall be allowed to recover its updated rate case expenses, including the Division's and Commission's expenses, amortized over a three year period, or $449,481 per year.

8. **Encroachment Expense.**

The Company's pro forma rate year expenses included $1,054,000 for additional operation and maintenance expenses relating to encroachment by increased public works

activities and third party excavations. Part of the increased expenses were based on the backlog of work existing in early 2008, and part were based on anticipated new encroachments. Ex. DIV-12 (Division Data Request 4-10). After reviewing the Company's actual encroachment expenses for the five months ending February 2008, the Division concluded that the rate of encroachment spending was well below the level reflected in the Company's pro forma rate year expenses and recommended a reduction of $756,000. Ex. DIV-1 at 9 (Effron). The Company accepted this recommendation. Division Post-Hearing Mem. at 27. The Commission approves the $756,000 reduction to the Company's pro forma test year operation and maintenance expense for encroachments, to $298,000.

9. Distribution Maintenance.

The company incurred actual distribution maintenance expenses of $16,804,000 in the test year. However, these expenses included costs incurred to reduce the backlog of Grade 2 gas leak repair work and paving restoration work arising before the beginning of the test year. Ex. DIV-1 at 10 (Effron); Ex. DIV-8 (Division Data Request 1-28); Ex. DIV-18 (Division Data Request 9-3); Ex. DIV-18 (Division Data Request 9-4). The Division concluded that the increased test year distribution maintenance expenses related to the backlog reduction were not continuing expenses, and recommended a reduction of $539,000 to the Company's pro forma test year operation and maintenance expense for distribution maintenance. Ex. DIV-1 at 11 (Effron). The Company accepted this position. Ex. NGrid-4, Attachment NG-MDL Rebuttal 1. The Commission approves the $539,000 reduction, and allows $16,265,000.

C. Revenue Reconciliation Proposals

1. Accelerated Capital Replacement Program

The Company proposed an accelerated replacement program ("ARP") to make upgrades to targeted portions of its delivery system. More specifically, the ARP will remove all

high pressure, bare-steel services from inside customer premises within five years. Tr. 9/9/08 at 42-44 (Fleck). The ARP will increase the amount of bare steel mains replaced annually, from 7.5 to 18 miles. Tr. 9/9/08 at 42-44 (Fleck). The Company also proposed to replace small-diameter cast iron mains on a more systematic basis. Ex. NGrid-5 at 17-21 and Attachment NG-SLF-1 (Fleck).

The Company initially proposed that the total cost of main replacement be funded through a reconciling mechanism. The Division objected that only the incremental cost of the accelerated replacement program, above pipeline replacement costs that would be incurred in the ordinary course, should be reconciled. The Company accepted this change. Ex. NGrid-4 at 17-18 (Laflamme Rebuttal); Tr. 9/8/08 at 78-83. The Company also agreed to limit upward rate adjustments for the accelerated replacement program if the Company's earnings are at or above its approved return on investment. *Id.* The Company states that its planned incremental spending is about $12 million, out of about $25 million total spending planned. Ex. NGrid-4, Attachment NG-MDL Rebuttal 6; Tr. 9/8/08 at 149-151 (Laflamme).

Company Position. The Company distributes natural gas to approximately 250,000 Rhode Island customers through a distribution infrastructure that includes approximately 900 miles of cast iron main, 440 miles of unprotected bare steel main and 240 miles of unprotected coated steel main out of a total 3,100 miles of main. Ex. NGrid-5 at 4, 15-16 (Fleck); Tr. 9/9/08 at 6-7 (Fleck); Ex. COMM-3 (Data Request COMM 2-7). Approximately 50% of the Company's Rhode Island distribution assets are leak prone, and the number of gas leaks is increasing. Since 2005, there have been over 1,400 gas leaks per year in the system, more than 50% higher than the leak rate of 900 per year for 1991-2004. Ex. NGrid-5 at 15-16 (Fleck). The leak rate has increased in spite of the fact that the Company and its predecessors

have replaced almost 120 miles of bare and unprotected coated steel mains in the last ten years. *Id.* The number of leaks per mile is higher in Rhode Island than in other jurisdictions where the Company operates. Ex. NGrid-5 at 16 (Fleck). For example, leakage rates in Rhode Island are more than seven times higher than in upstate New York. Tr. 9/9/08 at 73 (Fleck).

The Company has conducted a baseline assessment of its distribution assets and determined that at current replacement rates, continual system degradation from corrosion will undermine its ability to meet demand and operate the system safely and reliably. Ex. NGrid-5 at 16 (Fleck). The Company therefore proposed an accelerated replacement program ("ARP") to make upgrades to additional sections of its delivery system, selected based on such factors as the age and condition of the pipe, geographic location and expected growth in system demand. Ex. NGrid-5 at 17 (Fleck). The Company anticipates that its accelerated replacement plan will cause the number of gas leaks to begin to decline. A declining number of gas leaks is a reasonable measure of overall system safety and is the Company's goal. Tr. 9/9/08 at 26 (Fleck).

The Company also proposed removing all high pressure, bare-steel services from inside customer premises within five years. Approximately 8,261 such services exist today, which historically have been replaced at a rate of approximately 500 per year. The Company plans to accelerate the removal rate to approximately 1,600 units per year. Ex. NGrid-5 at 21 (Fleck). High pressure bare steel inside services need to be replaced because of the risk of corrosion where the high pressure gas line passes through the wall into the customer's basement. There is no way to inspect that part of the high pressure pipe. *Id.*; Tr. 9/9/08 at 141 (Ledversis). A survey conducted in the Company's Long Island territory demonstrated there is a resulting potential for failure and leaks. Tr. 9/9/08 at 43-48 (Fleck).

The incremental cost of the ARP, above pipeline replacement costs that would be incurred by the Company in the ordinary course, will be funded through a reconciling mechanism. The Company's planned incremental spending on the ARP is about $12 million , out of about $25 million total main replacement spending planned. Ex. NGrid-4, NG MDL Rebuttal 6; Tr. 9/8/08 at 149-151 (Laflamme). The incremental expense being proposed by the Company is based on safety concerns, not economic considerations. Tr. 9/9/08 at 164 (Laflamme).

Division Position. The Division supports the ARP in light of the documented growth in gas leaks in the distribution system, Tr. 9/9/08 at 135 (Ledversis), but suggests that (1) depreciation expense reductions related to ARP related plant retirements should be recognized; (2) the depreciation rate of mains and services, not the average composite rate, should be used to calculate incremental depreciation expense; (3) the calculation of incremental property tax expense should be modified so that it is based on the prior year's annual property tax expense to net plant in service; (4) the mechanism should apply to accelerated replacements, not routine replacements; and (5) there should be no rate adjustment if the Company is earning at or above its authorized return on equity. The Company has agreed to these modifications. Ex. NGrid-4 (Laflamme Rebuttal testimony at 17-18); NGrid Post-hearing Mem. at 49.

Commission Decision. The Commission finds that gas leaks create undesirable safety and environmental issues, and increase costs for ratepayers on account of lost commodity. Tr. 9/9/08 at 164 (Laflamme). The record reflects that historic pipeline replacement rates are not keeping pace with Rhode Island's aging gas distribution infrastructure, and that accelerated infrastructure replacement is in the interest of the ratepayers and the public as a whole. Ex. NGrid-5 at 16 (Fleck) (Rhode Island leaks per mile are increasing and are higher than in other

Company jurisdictions); Tr. 9/9/08 at 73 (Fleck). The Company's proposed increase in the annual replacement of distribution mains and its five year plan to remove high pressure inside services reasonably balances the need to measurably improve the safety and reliability of the Rhode Island natural gas distribution system in the near term against the burden to ratepayers of increased rates to pay for accelerated replacement. A reconciling mechanism is appropriate for the substantial incremental cost of the Company's proposed infrastructure improvements.

The Commission therefore authorizes the Company to implement the ARP, subject to the modifications recommended by the Division. Beginning in January 2009, the Company will submit a proposed implementation schedule to the Division each January for comment, and secure Commission approval. The Company will also submit a reconciliation report for each fiscal year. The first ARP reconciliation report for the 12 months ending March 31, 2009 will be submitted by May 15, 2009 for a rate adjustment effective July 1, 2009. The ARP will entitle the Company to a rate adjustment only to the extent of the capital cost that is incremental to the amount included in base rates in this proceeding. Tr. 9/8/08 at 79-83, 152-153 (Laflamme).

2. Gas Supply Related Bad Debt Cost.

The Company proposed to increase the portion of commodity cost bad debt embedded in the rate base from 2.1% to 2.46%, based on a five year average. Tr. 9/8/08 at 122-123 (Laflamme). The Company also proposed to recover or return any variance from the uncollectible ratio fixed in base rates through the GCR on a reconciling basis. Anticipated commodity related bad debt is currently fixed in base rates.

Company Position. Commodity bad debt is a component of the gas cost that should be recovered on a pass-through basis, as is the cost of the commodity itself. The change in policy will be beneficial to customers because the current structure locks in relatively higher

bad-debt recovery ratios, as well as relatively lower ratios, depending on circumstances at the time of a base-rate filing. Tr. 9/8/08 at 121-123 (Laflamme). The reconciliation would be based on the most recent five year average for net bad debt write-offs as of June 30 of each year. *Id.*; Ex. NGrid-15 at 13. Because the reconciling mechanism would apply only to bad debt related to commodity costs, and not bad debt related to distribution costs, the Company would still have a strong incentive to improve the uncollectible ratio. *Id.*

Division Position. The Division opposes a bad debt reconciliation mechanism because annual reconciliation would amplify price volatility for customers. Ex. DIV-3 at 79 (Oliver). The Commission has historically used a multi-year average of the Company's actual experience in base rates in order to mitigate year to year variations. Division Post-Hearing Mem. at 44; Ex. DIV-3 at 74-75, 79 (Oliver).

Commission Decision. The Commission finds that a bad debt ratio of 2.46% for base rates is supported by the record. The Commission declines, however, to approve the proposed gas cost-related bad debt reconciling mechanism. The Commission has historically used a multi-year average of the Company's actual experience in base rates in order to mitigate year to year variations, and finds that annual reconciliation of commodity-related bad debt cost is not in the best interest of ratepayers because it has the potential to amplify price volatility for customers. Ex. DIV-3 at 74-75, 79 (Oliver). Fixing the commodity-related bad debt ratio in base rates is not inconsistent with the Commission's treatment of commodity costs, which are recovered on a pass-through basis, because the Company has the ability to develop and implement measures to lower the uncollectible ratio.

3. Reconciliation of Pension and PBOP

The Company proposes to reconcile its pension and post-retirement benefits other than pension ("PBOP") expenses annually, and to adjust charges to ratepayers up or down accordingly to recover or return amounts above or below actual costs.

Company Position. Pension and PBOP expenses are volatile and beyond the Company's control because they respond to actuarial assumptions and financial market performance. They should be reconciled annually for several reasons.

First, a reconciliation mechanism will not reduce the Company's incentive to control benefit costs. The record shows that the principal alternative for reducing pension costs is the establishment of a defined contribution plan to replace the historical defined benefit plan. Tr. 9/8/08, at 138-139, 249. The record also shows that the Company has already taken steps to reduce pension costs that are within its control by preventing new employees hired after 2002 from entering into defined benefit pension plans. *Id.* at 139. Specifically, on January 1, 2005, all non-union new hires were placed in the Valley Gas pension plan design, which had a less generous formula for its participants. Ex. DIV-15 (Data Request DIV-6-22). Also, on January 1, 2005, post-retirement dental coverage for future non-union retirees was eliminated. Since National Grid's acquisition of the regulated gas operations in Rhode Island in August 2006, all non-union new hires were placed in the National Grid cash balance pension plan. *Id.* Lastly, effective March 31, 2008, all non-union employees that were covered under the Valley Gas or the Providence pension plan designs were transferred into the National Grid Final Average Pay pension plan. *Id.* Lastly, the Company has established an annual review process for pensions and PBOPs centering on: (a) actuarial assumptions, (b) vendor performance, and (c) medicare prescription drug program refund administration. *Id.* There is no basis to conclude that a reconciliation mechanism for pension and PBOP expenses will deter the Company from

continuing to make efforts to control the costs of these benefits and the Company has already made the change identified as the most significant opportunity for reducing costs, which is the transition from a defined benefit to defined contribution plan.

Second, the Company has demonstrated that the magnitude of pension expense as compared to the overall revenue requirement is great enough to warrant reconciliation. The pension and PBOP expense will account for approximately 6.4% of the Company's overall proposed revenue requirement of $150 million. Ex. NGrid-4, at 20. Contrary to the Division's assertions, this is a significant amount of expense for the Company to manage and it is as yet unclear what the impact of current market conditions will be on the pension and PBOP trust fund balances and resulting liability.

Third, the Company has demonstrated that the level of volatility for pension and PBOP is greater than other O&M expenses. Pension/PBOP expense and funding is subject not only to variation from year-to-year, but also is susceptible to periods of extraordinary fluctuation as a result of circumstances in the financial markets, which have been experienced in the recent years. Ex. NGrid-4, at 21. Fluctuations in the value of pension assets cause variations in pension and PBOP expense and funding levels. These volatile fluctuations are due to the stock market and are similar to the wild fluctuations in commodity prices like gas. In fact, both fluctuations in stock market prices and gas prices are beyond the control of the Company. Tr. 9/8/08 at 223-224. As an example of the volatility, contributions to the pension fund increased from $1,350,000 for the plan year ended December 31, 2002 to $2,858,158 for the plan year ended December 31, 2003 and totaled $5,388,000 for the plan year ended March 31, 2008. Ex. DIV-8 (Data Request DIV-1-8). For PBOP, information regarding funding, if any, is unavailable for the years under Southern Union ownership from 2003 through 2007, but the record shows

that National Grid made a contribution of $4,307,000 for the fiscal year ended March 31, 2008. Ex. DIV-8 (Data Request DIV-1-9). Thus, pension and PBOP expenses and funding can change dramatically from one year to another.

Fourth, the amount of pension and PBOP expense included in rates is not calculated to provide adequate funding without the need for a reconciliation mechanism. Fluctuations in the value of pension assets resulting from stock market changes leads to variations in pension and PBOP expense and funding levels. As a result, it is extremely difficult to establish a representative amount of expense in rates, especially where circumstances are occurring in the financial market that will impact the pension and PBOP plans beyond what is included in the expense levels that would be included in rates in this proceeding without a reconciling mechanism. In that regard, the present approach to funding pensions and PBOP creates a potential mismatch of what is embedded in rates for the FAS 87 and FAS 106 expense and what is actually contributed to the pension and PBOP funds. For example, for fiscal year ended June 30, 2004, $6,263,958 was expensed but only $3,626,754 was required for contribution by Southern Union for the plan year ended December 31, 2004. *Id.*

To ensure adequate funding of the pension fund and the PBOP in the future, a fully reconciling mechanism is the best approach because under the operation of the proposed mechanism it would assure that whatever the Company recovers from customers for FAS 87 or FAS 106 is actually contributed to the pension and the PBOP funds or reserved for in order to provide customers with an equitable economic benefit. Ex. NGrid-4 at 23. Without a reconciliation mechanism, there will inevitably arise a situation when the Company is recovering pensions and PBOP costs in base rates and contributing to the funds at a different level. *Id* at 24. Thus, a reconciliation mechanism will ensure that the Company funds the pension and PBOP

funds at the same level as amounts collected from customers. *Id.* Otherwise, there will be occasions when the Company will collect more in rates than it is required to contribute for pension and PBOP or the reverse.

It should also be noted that the proposed reconciliation mechanism for pension and PBOP is consistent with the Commission's recent directive in new England Gas Company, Docket No. 3690, Order No. 18780, which stated that "it is the long-term interest of ratepayers to have a properly funded pension fund." In that case, the Commission noted the mismatch between contributions to the pension fund and what is expensed for pensions over a number of years under New England Gas, and stated that this "difference . . . could be harmful to the pension fund in the long tem." A reconciliation mechanism is the best solution to this mismatch. Not surprisingly, in response to a question from the Commission concerning the possibility of an unfunded pension liability growing under the current rate structure, the Division's witness acknowledged: "[t]hat's the funding mechanism." Tr. 9/8/08 at 236-237. A reconciliation mechanism is the best funding mechanism to avoid an unfunded liability from growing for pension or PBOP.

Division Position. Reconciliation mechanisms are generally contrary to sound ratemaking principles, except for costs with large fluctuations beyond the Company's control that jeopardize its financial integrity. The Company has not presented evidence of the volatility of its pension and PBOP costs, or shown the potential of such costs to impair its financial integrity. Almost all other expenses in the Company's base cost of service are also subject to fluctuation. Division Post-Hearing Mem. at 30-31. Pension and PBOP expenses should be treated differently than GCR because gas costs are comparatively far greater, and therefore pose a far greater risk of a substantial under-recovery. Tr. 9/8/08 at 216-17, 221-24 (Effron).

Reconciliation is not needed to provide adequate funding for pensions and PBOP. Expense accruals are already calculated to provide adequate funding of the programs, even without a reconciliation mechanism. The pension program is currently 97% funded. Tr. 9/8/08 at 142 (Laflamme). This shows that the current method of regulation has not resulted in inadequate funding, and that annual reconciliation of pension and PBOP expense is not necessary. Tr. 9/8/08 at 245 (Effron).

Authorizing annual reconciliation would shift risk to the ratepayers. Tr. 9/8/08 at 217 (Effron). It also would reduce the Company's incentive prudently to manage its PBOP expenses. The Company has moved to reduce pension expense by instituting a defined contribution plan for new employees and making other changes. Tr. 9/8/08 at 139-140 (Laflamme); Ex. DIV-15, NGrid Response to Division Data Request 6-22. The Division questions whether the Company would have undertaken these pension cost control measures if a pension and PBOP cost reconciliation mechanism had been in place. Division Post-Hearing Mem. at 33.

Commission Decision. While the Commission in general disfavors reconciliation mechanisms, they have been approved in the past for certain items. For example, the Company recovers its commodity costs through a reconciliation mechanism. The Commission has also approved a reconciliation mechanism for unpredictable and potentially costly environmental remediation measures. Ex. NGrid-4 at 22 (Laflamme Rebuttal). While not as large as commodity costs, the Commission finds that the Company's pension and PBOP expenses are sufficiently large and unpredictable to justify an annual reconciliation mechanism. The record reflects that these expenses can be subject to substantial fluctuations as a result of changes in the

financial markets that affect pension asset values, and that these fluctuations are beyond the Company's control. Ex. NGrid-4 at 21 (Laflamme Rebuttal).

The Company's pension program is currently 97% funded. Tr. 9/8/08 at 142 (Laflamme). However, the record suggests that under the current methodology, its predecessor, Southern Union, may have funded pensions at the minimum tax deductible level rather than contributing the full amount approved in rates. Tr. 9/8/08 at 135 (Laflamme). For the fiscal year ended June 30, 2004, $6,263,958 was expensed but only $3,626,754 was required for Southern Union's contribution for the plan year ended December 31, 2004. Ex. DIV-8 (Data Request DIV 1-9); NGrid Post-Hearing Mem. at 56. A reconciling mechanism will give ratepayers greater assurance that the Company is funding pension and PBOP funds at the same level as amounts collected from customers.

Under the Company's proposal, ratepayers would assume the risk of investment losses currently borne by shareholders. Tr. 9/8/08 at 136-137 (Laflamme). However, since 2002, new Company employees have been placed in a defined contribution plan, mitigating this risk. *Id.* at 139-140; Ex. DIV-15, NGrid Response to Division Data Request 6-22. The Company has also taken other steps to reduce future pension and other benefit expense, including placing employees in less generous plans and eliminating post-retirement dental coverage for future non-union retirees. Ex. DIV-15 (Data Request DIV 6-22). The Company plans to make further efforts to control pension and PBOP costs regardless of whether the reconciling mechanism is approved: for example, the Company has established an annual review process for pensions and PBOP expenses to assess actuarial assumptions, vendor performance and medicare prescription drug program refund administration. *Id.*; NGrid Post-Hearing Mem. at 53-54; ; Tr. 9/8/08 at 147-148 (Laflamme). Therefore, the Company's exposure to pension

investment losses has been reduced in recent years, and the proposed reconciling mechanism does not create unreasonable new risks for ratepayers.

Reasonable pension and PBOP expenses are legitimate and unavoidable costs of operating the distribution system. To the extent that fixing pension and PBOP expenses in the base rates leads over time to the pension being underfunded, current ratepayers are effectively shifting greater pension and PBOP expense to future ratepayers. The Company's proposed reconciliation mechanism more closely matches present rates with present pension and PBOP expense, and is in the interest of ratepayers. The Commission approves the Company's proposed pension and PBOP mechanism.[9]

D. Revenue Decoupling

The Company's filing proposed to implement for the first time in Rhode Island a full revenue decoupling mechanism ("RDM"). As initially proposed, the RDM applied to all firm rate classes, with certain exemptions for new large customers. Ex. NGrid-12 at 2-7 (Simpson). The Company thereafter modified its proposal to exempt the four large and extra large firm rate classes. Tr. 9/12/08 at 5-6. Low income customers were subsequently excluded as well. Tr. 10/22/09 at 8-11; NGrid Post-Hearing Mem. at 62-63. The remaining classes (residential non-heating, residential heating, small C&I and medium C&I) include most of the Company's customers and generate more than 80% of the Company's distribution revenue. Ex. NGRid 15 Appendix NG-PCC-3; Tr. 9/26/08 at 167-168.

The RDM would set a target revenue per customer amount for customers in the affected classes. The target revenue per customer would be set at an amount sufficient for the Company to recover the base rate revenue requirement for that customer class approved in this

[9] Commissioner Bray dissents from this decision and would adopt the Division's position for reasons stated on the record at the November 24, 2008 Open Meeting. Tr. 11/24/08 at 78-80.

rate case. To the extent actual revenue per customer in the affected classes exceeded or fell short of the target, the surplus or shortfall would be credited or collected through an annual adjustment of the DAC.

The Company's decoupling proposal generated substantial briefing and testimony at the hearings from the parties and intervenors. The principal arguments presented for and against decoupling are summarized below.

Company Position. The Company argues that decoupling will "eliminate the Company's dependence on gas consumption to obtain necessary revenues to run the business," and will "allow [it] to aggressively promote conservation through new energy efficiency, without harming revenues." Company Opening Statement, at 29. Natural gas usage per customer has steadily declined, and the declines are expected to continue. Ex. NGrid-12 at 15-17 (Simpson). Because of declining usage per customer, the Company asserts that traditional ratemaking no longer works. Declining usage deprives the Company of revenues that have been allowed by the Commission as reasonable and prudently incurred. Ex. NGrid-2 at 18 (Stavropoulos).

Decoupling is "a vehicle for recovery of the revenue requirement approved in this case," NGrid Post-Hearing Mem. at 64, and nothing more. Decoupling will not insulate the Company from cost increases occurring in the normal course of business, some of which are highly sensitive to inflation, including labor, construction materials, and fuel costs. Therefore, the Company has the same incentive to reduce costs that it would have without decoupling. *Id.* at 65-66.

The Company disputes that the period of time that has passed since the last rate case demonstrates that the Company does not need an annual decoupling adjustment. The timing of this rate case is attributable to a rate freeze in effect through June 2005 and the transition of

ownership from Southern Union to National Grid. *Id.* at 69. The Company has not achieved its authorized ROE since fiscal year 2005, and declining gas usage per customer accelerated in 2004-2006. NGrid Post-Hearing Mem. at 70. The Company would not have made its authorized ROE from 2005 through 2008 even with decoupling. *Id.*

The Company also disputes that (1) weather normalization adjustments, higher fixed charges or declining block rates are alternatives to decoupling, (2) decoupling is unnecessary in light of state energy efficiency mandates, (3) decoupling will produce large annual rate increases for customers, and (4) decoupling will reduce customer incentives to conserve.

First, weather normalization, higher fixed charges, and declining block rates do not eliminate sensitivity of the Company to reduced revenues due to conservation (Tr. 10/23/08 at 180), which is demonstrated by the fact that all of these items were in place for the Company over the past five years and did not have the effect of maintaining revenues in the face of declining consumption. This is because higher fixed charges and declining block rates maintain a level of revenues despite declines in consumption but do not eliminate the impact caused by a reduction in use per customer. Tr. 10/22/08 at 99. Moreover, weather normalization does not protect against conservation, it simply operates to eliminate weather-related deviation from *average* from period to period. Over time, the cumulative weather normalization adjustments should approach zero as cumulative period to period weather approaches *average*. Ex. NGrid-13, at 31; Tr. 10/22/08 at 47. Also, a rate-design structure with higher fixed charges reduces the price signal to consumers to conserve. Tr. 9/26/08 at 172; Tr. 10/23/08 at 73. Thus, decoupling is the best means to generate the allowed level of revenues in the face of declining consumption, while maintaining appropriate price signals to customers.

Second, the record shows that decoupling will remove the disincentive for companies to reduce sales and has the potential to align the interests of utility with conservation. Tr. 9/29/08 at 164-165; Ex. TEC-RI-1, at 19. The record also shows that disincentives have a significant influence on utility policies and that utilities are key players in promoting conservation. Tr. 10/23/08 at 68, 73-74. The implementation of decoupling will encourage the Company to use its full expertise and resources to reduce customer usage. In contrast, although the utility will conduct a state-mandated program to the best of its ability, it has a disincentive to go beyond the confines of that program to promote conservation on a creative or aggressive basis. Tr. 10/22/08 at 28. Also, the incentive the Company receives for its gas DSM program is relatively small in terms of removing the Company's concern about revenues on a system-wide basis. *Id.* at 32.

Third, under traditional ratemaking, there are fewer, but larger rate increases, while decoupling increases occur on an annual basis to a lesser amount. Tr. 9/26/08 at 177. For instance, TEC-RI's expert witness agreed that the increase due to decoupling would be approximately $500,000 in 2007 and about $1,000,000 in 2008, and that these increases for 2007 and 2008 are relatively small. Tr. 9/29/08 at 92, 94-5. Cost increases of that size occur now with weather normalization. For example, weather normalization led to an increase of $927,000 in 2006 and $882,000 in 2007. Ex. TEC-RI-3 (Data Request TEC-RI 1-7). Thus, the concern regarding large annual increases is unfounded.

Fourth, decoupling will not reduce the incentive to conserve. Under the Company's decoupling proposal, customers will still be billed based on consumption, and the annual decoupling rate adjustment will be added or credited to the DAC. In addition, the decoupling rate adjustment is based on billed delivery charges only, where commodity revenues

account for 2/3 of the customer bill. Tr. 9/26/08 at 121-23. In the unlikely event that all residential heating customers installed conservation measures that reduced usage by 10 percent, which would theoretically produce a decoupling rate adjustment that would offset the delivery charge benefits of the conservation measures, the typical residential heating customer would still realize savings on the GCR portion of his bill, which is 70 percent of the bill. The average savings would be 4.7 percent or $71.43. Ex. NGrid-13, at 18-19. In addition, the decoupling rate adjustment will also be based on consumption which could also produce a price signal encouraging conservation. Thus, the record shows that in practical application the decoupling rate adjustment will not offset the delivery rate savings a customer would receive from conservation in addition to the GCR savings the customer will enjoy as a result of conservation.

Division Position. Decoupling has been approved in only a limited number of jurisdictions, mostly within the last two years. There is not much evidence of its impacts on ratepayers. This would be the first approval of decoupling for a gas utility in New England, and the first for National Grid in the U.S. Rhode Island would be an experimental starting point for the Company. Division Post-Hearing Mem. at 45, 48.

The Company already has at least four types of revenue decoupling included in its tariff: (1) a weather normalization adjustment; (2) declining block rates for residential heating and small commercial and industrial customers; (3) demand charges for medium, large and extra large commercial and industrial customers that are adjusted to reflect usage in the prior winter; and (4) the use of a future test year to reflect known reductions in consumption. Full revenue decoupling is not necessary or desirable. Divison Post-Hearing Mem. at 53; Ex. DIV-3 at 5; Tr. 10/24/08 at 9-10.

There is no evidence that full decoupling will produce energy conservation beyond what could be achieved under existing DSM programs. The Company has in the past systematically touted the success of DSM programs and its own commitment to executing cost-effective and innovative conservation programs. The Company is capable of maintaining its commitment to carry out what the Commission has already ordered and what state law mandates without a decoupling mechanism. Division Post-Hearing Mem. at 45-48, 53. A commitment to "reach for the stars" in the future is not a sufficient basis to order decoupling. *Id.* at 49, 53. Ratepayers will pursue energy efficiency regardless of whether decoupling is adopted. *Id.* at 53.

The Company's decoupling mechanism insulates the Company against revenue declines for any reason, not just conservation efforts. It essentially reduces the Company's revenue risk to zero. By divorcing Company performance from revenues, it shifts responsibility to the Commission to ensure that appropriate system and service quality are maintained. Revenue erosion from DSM is already reflected in rate year billing determinants, so the Company does not need decoupling to earn a fair return. Division Post-Hearing Mem. at 48-49; Tr. 10/8/08 at 24 (Czekanski).

Had revenue decoupling been in effect since the last rate case, the Company would have been insulated from revenue losses resulting from the "serious distraction" of the Southern Union and KeySpan mergers. There is evidence that the Company would have received an additional $34.1 million over the four year period with decoupling. Division Post-Hearing Mem. at 49-51; Tr. 9/26/08 at 100.

Approval of an annual reconciliation for accelerated pipeline replacement expenses mitigates any concern that traditional ratemaking procedures will not allow the Company to invest in infrastructure. *Id.* at 51.

Approving full decoupling raises complex issues regarding how to apply a weather normalization adjustment to rate classes exempted from the decoupling mechanism. If full decoupling is approved, the Commission's only option is to allow service to classes exempted from decoupling without any weather normalization adjustment. Division Post-Hearing Mem. at 54 n. 127.

Traditional regulation works. The Company has an appropriate incentive to exercise prudent cost management, and can periodically apply for a rate increase if necessary. This allows the Commission to review revenues and expenses together. Decoupling could potentially weaken Commission oversight of the Company by making rate cases more infrequent. *Id.* at 53. Decoupling will also discourage rate case settlements that could involve rate freezes or rate caps. Tr. 8/27/08 at 164.

Environment Northeast. ENE supports the proposed RDM, as modified. Full decoupling will help achieve the state's economic, energy efficiency, and environmental goals by better aligning the Company's financial incentives with customer and public policy interests in maximizing investment in efficiency efforts that are cheaper than supply. Under the current tariff, the Company derives a significant portion of its revenue through volumetric distribution rates. The Company therefore has an economic disincentive to support programs that would result in the reduction of gas consumption. The RDM would eliminate this disincentive for included rate classes. Because a portion of the distribution revenue would continue to be collected through volumetric rates, customers will still have an economic incentive to conserve on both the commodity and distribution parts of the bill. ENE Post-Hearing Mem. at 3-5. California has had a long, successful history with decoupling. Massachusetts has recently adopted it. *Id.* at 19-20

The Company is in a unique position to effect positive ratepayer decisions regarding efficiency investments, and can do so more forcefully with decoupling. State law already authorizes the Company to administer gas efficiency programs funded through a volumetric charge. R.I.G.L. § 39-2-1.2(d). State law recognizes that DSM programs may affect utility revenues and authorizes a rate adjustment clause to provide for full recovery of reasonable and prudent costs of a company implementing conservation procurement. R.I.G.L. § 39-1-27.7(d). The proposed RDM is consistent with this law because it would allow full recovery, and disallow over-recovery, of such costs. ENE Post-Hearing Mem. at 12-15.

State law authorizes utility efficiency programs, but does not mandate the level of investment or parameters of the programs. ENE Post-Hearing Reply at 5. Decoupling will encourage the Company to favor practices that promote efficiency and conservation, including advocating for tighter codes and standards, pushing technological improvements, and shaping the competitive marketplace for more efficient products. *Id.* at 3, n. 7. Rhode Island's per capita natural gas consumption (excluding usage for electric generation) is 37th in the country, and there are still a great deal of energy efficiency investments that are less costly than supply. *Id.* at 2-3, 5. While some customer conservation will occur without decoupling, there is strong evidence that utility DSM programs are important to remove cost barriers, perceived technology risks and information gaps that impede conservation. *Id.* at 5.

Existing so-called "partial" decoupling mechanisms such as weather normalization do not eliminate the Company's sensitivity to sales volumes. Decoupling does not guarantee Company profits. The Company will need to manage its costs carefully to earn its allowed return. The Company's motivation to reduce expenses and be efficient will be the same. *Id.* at 16-17; ENE Post-Hearing Reply at 6-7.

Excluding the four large rate classes from the RDM addresses ENE's concern that applying decoupling to small, heterogeneous rate classes could have unintended negative consequences. *Id.* at 18; ENE Post-Hearing Reply at 7-8. The RDM's design also eliminates any risk of cross-subsidization among classes. ENE Post-Hearing Mem. at 19; Tr. 9/12/08 at 10.

Conservation Law Foundation. CLF supports decoupling. Climate change is a crucially important issue to which the Commission should pay attention. Decoupling eliminates the disincentive to conservation and efficiency that exists in traditional ratemaking and aligns the utility's incentives with the public interest. CLF Post-Hearing Mem. at 3-6. State utility commissions in North Carolina, Ohio, Maryland, New York and Massachusetts have recognized the disincentive to promote energy conservation under traditional ratemaking and have ordered decoupling in recent dockets. CLF Proposed Findings of Fact at 10-12.

Traditional ratemaking does not work today as it has in the past because of declining gas use. As a result of declining use, the Company has been deprived of revenues allowed by the Commission. This has had an impact on safety because the funds are needed to operate the distribution infrastructure. The Company's proposed RDM true-ups ensure that the Company will receive its revenue requirement, neither more nor less. Moreover, the Company proposes maintaining the earnings sharing mechanism so that the Company and customers will share in earnings that exceed the allowed ROE. CLF Proposed Findings of Fact at 4-6.

Energy conservation and efficiency that would be fostered by decoupling will reduce overall gas consumption and benefit ratepayers by helping them avoid embedded carbon costs that will in the future be part of commodity prices. Reduced emissions of carbon dioxide will also ameliorate climate change. *Id.* at 8-9. CLF has opposed the Company in other dockets, but supports it here.

CLF disputes that the proposed RDM will erode incentives for customers to conserve energy. Approximately 70% of a ratepayer's bill is the commodity charge, which will decline in direct proportion to declining use. The remaining 30% is the distribution charge, which is also collected volumetrically. Even if the distribution rate increases because of the RDM adjustment, it would be offset by declining volume usage. *Id.* at 12-13.

TEC-RI Position. TEC-RI opposes decoupling. Decoupling is a major departure from traditional ratemaking, and can have a significant impact on ratepayers. NGrid Response to TEC-RI data request 1-7; NGrid Response to data request TEC 1-77 (15 states have approved decoupling). If decoupling had been in effect over the past four years, ratepayers would have paid an additional $34 million. Tr. 9/26/08 at 100; TEC-RI Post-Hearing Mem. at 13.

The Company has presented no evidence demonstrating that decoupling would produce more energy efficiency. It presented no new energy efficiency proposals to be implemented in Rhode Island, or efficiency studies from other jurisdictions with decoupling. Rhode Island already has the lowest energy use per capita, and ranks high in per capita utility energy efficiency spending. Decoupling is not needed, as indicated by the Company's request to withdraw its decoupling proposal from this rate case. TEC-RI Post-Hearing Mem. at 15; Tr. 9/8/08 at 5-7 (denying motion to withdraw).

Decoupling is not mandated by R.I.G.L. § 39-1-27.7(a)(2)(d). That statute (1) applies only to electric utility distribution, (2) permits, but does not require, adjustment, and (3) only allows rate adjustment for costs of system reliability, energy efficiency and conservation procurement, not for revenue changes regardless of the cause as allowed by the Company's proposed RDM. TEC-RI Post-Hearing Mem. at 16. The proposed RDM shifts risk from the Company to the ratepayer, but does not compensate ratepayers for assuming this risk. *Id.* at 17.

If decoupling is approved, large and extra large rate classes should be excluded. These classes have small numbers of customers and large variability in revenues among customers. Small changes in class membership could result in RDM adjustments that are not related to conservation efforts. Excluding these classes would not lead to cross-subsidization because RDM adjustments are calculated by class. No party opposes excluding large and extra large customers from the RDM. TEC-RI Post-Hearing Mem. at 10-11.

Office of Energy Resources. Rhode Island Office of Energy Resources opposes decoupling. OER states that "the record does not provide either a logical or a legal basis for adopting the proposed decoupling adjustment at this time." OER Post-Hearing Brief at 2; OER Post-Hearing Reply at 4 (there is "no empirical evidence to define the weight and nature of the claimed disincentive"). OER also states that the Company has already accounted for known and measurable future lost volumes in its rates, *id.* at 3, and that it has the management tools to offset any alleged disincentive to promote gas efficiency. *Id.* at 4. The record does not show why the Company cannot overcome any existing disincentive to promote conservation with existing management tools. OER further states that R.I.G.L. § 39-1-27.7(d) authorizes, but does not mandate, a decoupling adjustment. *Id.* at 5.

No customers support decoupling. Large and extra large C&I customers and low income customers have convinced the Company to exclude them. The remaining customers, represented by the Division, do not support decoupling. OER Post-Hearing Reply at 7.

Wiley Center. The Wiley Center opposes the Company's RDM, which shifts to ratepayers the risk of lost revenue from drops in usage regardless of the cause of those drops, and does not provide for a commensurate reduction in the Company's rate of return. If decoupling is approved, low income customers should be excluded. Low income customers cannot afford to

pay more for gas service. The RDM will result in an increase in the cost of gas service for the foreseeable future, as gas usage is decreasing. Wiley Post-Hearing Mem. at 9-10; Ex. Wiley 1 at 10 (Pre-Filed Direct).

Attorney General. The Attorney General adopts the Division's position on decoupling. Opening Remarks of the Attorney General at 1. Should the Commission adopt decoupling, however, the Commission should exclude low income residential heating and non-heating customers from the RDM. RIAG Post-Hearing Mem. at 1 n. 1.

Commission Decision. The record reflects that consumption of natural gas per customer has been declining since at least 1980. Ex. NGrid-12 at 28-29 and Attachment NG-JDS-4 (Simpson Direct). Some of the reduction in consumption is related to passive conservation measures, such as the forced replacement of old, failing gas appliances with new models that a re more energy efficient. Ex. NGrid-12 at 18 (Simpson). Other reductions are the result of active conservation measures, often in response to commodity price increases. *Id.* at 20-21. The impact on natural gas utilities of declining use per customer over the years has apparently been manageable with traditional ratemaking, under which gas utilities facing substantial usage declines are free to apply for a rate increase. It is clear that the Company's inability to earn its allowed return on equity in recent years is as attributable to the Company's own business activities as to declining use per customer. The last rate case involving the Company's Rhode Island natural gas operations was Docket No. 3401 in 2002. In the settlement of that rate case, the Company's predecessor agreed to a rate freeze until June 30, 2005. The Company cited its merger activity in 2006 and 2007 to explain its failure to request a base rate increase in those years. Tr. 9/12/08 at 90-95 (Simpson).

The Company states that the "primary reason for the Company's [decoupling] proposal is to advance the goal of achieving greater energy efficiency in the State of Rhode Island." Ex. NGrid-2 at 13 (Stavropoulos). Yet there is little or no evidence in the record to demonstrate how or why this would occur. The Company has not identified any new conservation or energy efficiency initiatives that it would undertake in the event that decoupling were approved. No party presented any study or analysis of additional energy efficiency that decoupling would produce in Rhode Island.

The Company's incentive or disincentive to embrace conservation initiatives in the absence of decoupling was the subject of conflicting testimony. A Company witness testified that incentives influence utility behavior, and that decoupling would cause the Company to reach for the stars in developing new conservation initiatives. Tr. 10/22/08 at 28 (Stavropoulos). Certain intervenors also testified that decoupling could be expected to induce the Company to more aggressively pursue conservation and energy efficiency. Tr. 10/23/08 at 68-69, 88 (Kaplan). On the other hand, the Division's expert witness testified that while decoupling might affect the Company's behavior, it would not necessarily have any impact. The Division's expert suggested several reasons why financial incentives might not affect the Company's behavior at all. Tr. 10/21/08 at 208 (Oliver).

The fact that decoupling may eliminate a disincentive for the Company to promote conservation, even if true, does not necessarily translate into any significant reduction in consumption above what would have been achieved as a result of local and national economic pressures, technology improvements, and other extrinsic factors. Regardless of decoupling, most customers will have an incentive to conserve because reduced usage translates directly into lower

commodity charges for the customer, and commodity costs currently account for over two thirds of the average residential bill.

Revenue decoupling would protect the Company from revenue declines attributable to any cause, not only energy conservation and efficiency efforts. Ex. DIV-5 at 37 (Rothschild) (decoupling would "significantly reduce the non-diversifiable risks exposure to NG investors by a revenue stream that would be essentially unaffected by swings in economic conditions in the service territory."). Decoupling would reduce the Company's revenue risk to zero, and shift the risk of revenue variations to ratepayers. Tr. 10/22/08 at 76 (Stavropoulos). While the record includes substantial evidence of the benefits of decoupling to the Company, the evidence that decoupling will benefit ratepayers is largely speculative. Indeed, the record reflects the significant financial impact on ratepayers that decoupling might have. Over the last four years, revenue decoupling would have resulted in an additional $34 million of payments to the Company. Ex. TEC-RI-3 (NGrid Response to TEC-RI Data Request 1-7); Tr. 9/26/08 at 100 (Simpson) ("If the revenue decoupling mechanism had been in effect for all rate classes the net effect would have been the $34 million that Mr. Farley calculates.").

The Company is already protected from revenue variations caused by unusually cold or warm weather, through the weather normalization adjustment. It is also allowed to adjust demand charges for medium, large and extra large commercial and industrial customers based on usage during the prior winter. The Company is also allowed to recover its commodity cost and, as a result of this docket, to reconcile its expenses for pension and PBOP costs and for the accelerated capital replacement program. These mechanisms already protect the Company against unanticipated revenue shortfalls in many areas, and mitigate the need for full decoupling.

Certain intervenors emphasize that other utility regulators have approved decoupling, and suggest that the Commission should follow their example. *See, e.g.*, CLF Post-Hearing Mem. at 10-11. The decisions of other regulatory bodies are not evidence that decoupling would materially contribute to energy conservation and efficiency in Rhode Island. Over time, the adoption of decoupling in other states may produce concrete evidence of ratepayer benefits that could reasonably be expected to occur in Rhode Island, but that has not yet occurred.

After careful consideration of the evidence and arguments presented by the parties and intervenors, the Commission finds that the Company has not carried its burden of proof on the proposed RDM. The parties agree that full revenue decoupling would be a significant change in traditional ratemaking policy in Rhode Island. To adopt full revenue decoupling, the Commission needs more than speculative assertions that it would promote additional conservation or energy efficiency. The record reflects that decoupling is still relatively new and untested in the United States, having only been approved by fifteen states, many of them within one to two years. Ex. TEC-RI-3 (NGrid Response to data request TEC 1-77); *see* Ex. CLF-3 (Mass. Department of Public Uitlities); Ex. CLF-5 (North Carolina Utilities Commission); Ex. CLF-7 (Maryland Public Service Commission); Ex. CLF-8 (New York Public Service Commission). The impact of full decoupling on utility behavior and on ratepayers is not clear.

Traditional ratemaking has worked well in the past. The Commission is responsible for reviewing utility operations, and a full base rate case where witnesses are subject to examination and cross-examination is a valuable opportunity to look at the entire operation of the Company. Revenue decoupling may have the undesirable consequence of further enlarging

the period between rate cases, thereby reducing public oversight. The Commission is not persuaded that experimenting with full revenue decoupling is appropriate at this time.[10]

E. Low Income Discount.

The Company proposed a 10% discount off of Commission-approved customer and distribution charges for low-income residential heating and non-heating customers eligible for LIHEAP assistance. Approximately 16,000 heating customers and 2,500 non-heating customers would be eligible. NGrid Post-Hearing Mem. at 92; Ex. NGrid-30 (tariff changes). The Company estimates that average savings for a low income residential heating customer would be approximately $54 per year. The estimated impact of the proposed 10% discount is approximately $800,000 to be recovered from other firm customers. The Company proposed that the cost of the discount be allocated based on consumption, although it had no objection to a different allocation method. Tr. 9/11/08 at 160 (Czekanski); NGrid Response to TEC-RI Record Request No. 1.

Company Position. The Company believes that a 10% low income discount reflects the proper balance between the interests of poor customers and other ratepayers. Tr. 9/11/08 at 159-160, 164-165 (Czekanski); Ex. DIV-13 (NGrid Response to Division Data Request 5-19). The 10% low income discount would supplement other existing assistance for low income customers. For the twelve months ending June 30, 2008, $9,108,481 was available to help reduce the bills of low income gas customers. NGrid Response to Record Request No. 21. In addition, $983,643 was available to support low income customers' energy efficiency efforts. *Id.*

[10] Commissioner Holbrook dissents from this portion of the decision and would allow full revenue decoupling for reasons stated on the record at the November 24, 2008 Open Meeting. Tr. 11/24/08 at 13-24.

Division Position. The Division takes no position on the proposed 10% discount on the grounds that the appropriate level for low-income rate assistance "is a highly subjective matter . . . and [the Division] is not in a position to render an opinion regarding the reasonableness or appropriateness of either the proposed rate discount levels . . . ." Ex. DIV-3 at 69 (Oliver).

TEC-RI Position. TEC-RI does not object to the 10% discount. However, TEC-RI opposes allocating the cost to other ratepayers based on class consumption. Under this method, rates for non-residential customers will be increased twice as much as rates for residential customers to pay for the low income discount. This method is different than the methods used by the Company in New York and Massachusetts. TEC-RI proposes that the cost of the discount be allocated to rate classes using a rate base allocator (class rate base as a percent of total rate base). TEC-RI Post-Hearing Mem. at 22, 25.

Wiley Center Position. The Wiley Center proposes a low income discount of 50%. The economic crisis has deepened since the 10% discount was proposed. The annual out of pocket cost of utilities for the average low income household, taking LIHEAP and other assistance into account, is around $990 for gas and $823-$900 for electricity. This is about 13% of a minimum wage earning customer's wages, and 24% of the amount of assistance provided to a family of four on public welfare. Wiley Post-Hearing Mem. at 1, 5-6.

A low income discount is permissible under R.I.G.L. § 39-2-5(2) if it is "just and reasonable" or "in the interest of the public," and is not "unjustly discriminatory." The record shows that (1) the hardship borne by low income customers has worsened over the years, (2) low-income customers have been more severely affected by recent increases in commodity costs than other customers, (3) the discount may lessen the cost of terminating and restoring low

income customers, benefiting other ratepayers, and (4) other ratepayers may benefit as well from the stipulated $150,000 reduction in uncollectible expense. Wiley Post-Hearing Mem. at 2-4. The discount may also produce indirect ratepayer benefits from reduced health and public safety costs, and increased economic and educational productivity of low income customers. Ex. WC-1 at 9, WC-2 at 1 and App. 4. The impact on other residential and small and medium C&I customers ($2.21/year, $3.05/year and $26.28/year respectively on average, assuming the cost is spread volumetrically as proposed by the Company) is small. Ex. WC-3 at Data Request 1-8.

Utility regulators in Massachusetts, New Hampshire and Maine have added new protections for low income customers. In September 2008, the Massachusetts Department of Public Utilities ordered utilities to increase low income gas and electric discounts immediately, and the New Hampshire PUC increased the amount that other customers would pay to support tiered low income electric discounts. In August 2008, the Maine PUC increased funding for its electric low income assistance program by 13%. Wiley Post-Hearing Mem. at 7-9.

Attorney General's Position. The Attorney General "believes that the proposed discount is appropriate and reasonable in light of the value of the company's existing program and the substantial price increases that heating customers have experienced over the past year." Opening Remarks of the Rhode Island Attorney General, at 2.

The Commission possesses express statutory authority under R.I.G.L. § 39-2-5(2) to grant free utility service upon such conditions as the utility may impose, and may grant special rates to any special class or classes of persons so long as the rates are just and reasonable or in the public interest and are not unjustly discriminatory. The provisions of R.I.G.L. § 39-2-5(13) do not limit this authority. The expenses associated with the proposed low income discount are just and reasonable; the discount is not unjustly discriminatory; and the discount is in the public

interest. The Commission should allow all expenses associated with the discount as proposed. RIAG Post-Hearing Mem. at 20-27.

Commission Decision. The record evidence establishes that utility costs are a heavy economic burden for many Rhode Islanders, particularly those with very low incomes. The Commission finds that the proposed 10% discount offers a just and reasonable level of relief for the poorest Rhode Islanders, and is not unjustly discriminatory. For an average low income residential heating customer, the savings will be $49 per year. NGrid 11/26/08 Compliance Filing Attachment NG-Compliance RD-3, page 1 of 4. The Commission finds that the Wiley Center's proposed 50% discount is not supported by the record. All Rhode Islanders are facing unusually difficult economic times, and the approximately $800,000 cost of the 10% discount will be funded by other ratepayers, who in some cases may be only slightly better off than the discount recipients. The cost of the 10% low income discount to residential heating customer may be only a few dollars, but is only one of many increasing costs that cumulatively can be significant. Greater discounts face a heavier burden of proof of reasonableness, in light of their increasingly disproportionate benefit to the low income class and greater impact on other ratepayers to whom the cost of the discount is shifted.

The cost of the discount will be collected from other ratepayers based on consumption, as proposed by the Company. The Commission does not agree that TEC-RI's proposal to allocate the cost of the discount based on class revenue is appropriate.[11]

The Commission does not have the authority to require the Company to contribute shareholder funds to the proposed discount. The Company has made a voluntary contribution of $200,000 to the Good Neighbor Energy Fund, an amount that is equal to approximately 25% of

[11] Commissioner Holbrook dissents from the Commission's decision to approve the 10% low income discount and would refer this issue to the Rhode Island General Assembly, for the reasons stated on the record at the November 24, 2008 Open Meeting. Tr. 11/24/08 at 82-85.

the estimated cost of the discount that will be paid by ratepayers. The Commission urges the Company to consider increasing the amount of its voluntary contribution from shareholder funds to match the ratepayer funds that are being collected on account of the discount.

The Rhode Island General Assembly has in the past established a statewide energy affordability program, but the program was never funded and has now been repealed. The Commission would welcome the renewal and funding of that program. The Commission believes that a statewide energy affordability program approved and funded by the Rhode Island General Assembly would provide more accountability and, possibly, more resources for the energy costs of low income Rhode Islanders. The Commission's discretion to allow discounts is limited by the statutory requirement that any discount is just and reasonable and not unjustly discriminatory.

F. Non-Firm Tariff Issues.

1. Pricing for Non-Firm Transportation Customers.

Non-firm customers have dual-fuel capability, and agree that their gas service may be interrupted by the Company. Under the current "value of service" tariff, non-firm transportation service pricing changes monthly based upon the amount the customer would pay for its alternative fuel less a discount related to the customer's volume of consumption. The Company proposes maintaining the present "value-of-service pricing" for non-firm transportation customers, capped at 150% of the applicable firm service rate. The Division and certain intervenors propose "cost of service" pricing for interruptible service instead. The cost of non-firm service would be calculated based on a set discount off of the cost of firm service.

Company Position. The current tariff employs value of service pricing for non-firm customers. The tariff sets prices for non-firm customers such that the cost of the distribution charge and commodity charge combined is at a discount of between 2.25% and 22%

off the cost of the non-firm customer's alternative fuel (subject to a floor price of 10 cents/Dth in summer and 16 cents/Dth in winter). Value of service pricing acts as an incentive for non-firm customers to use gas distribution capacity that would otherwise be wasted, while simultaneously maximizing revenue for firm customers. The revenue impact of moving from value of service to cost of service pricing could be substantial for firm customers. Ex. NGrid-36; Tr. 10/8/08 at 6-17 (Czekanski).

As of September 1, 2008, there were 32 active non-firm service accounts. NGrid Response to Division Record Request No.-6. A preliminary engineering review conducted by the Company shows that 12 non-firm service customers can not be served as firm customers without system enhancements. *Id.* The estimated cost of the enhancements to bring a particular non-firm customer on line ranges from $9,000 to $3 million, depending on the customer. The estimated total investment needed to offer firm service to all existing non-firm customers is at least $9 to $10 million. *See* NGrid Response to Division Record Request No. 7.

The Company does not support a cost based rate for non-firm customers because a cost-based rate would normally include the cost of building and maintaining the system to meet the needs of all firm customers at peak periods. Allocating all of the system costs to firm customers implies that the cost of serving non-firm customers is equal to the marginal cost of service (primarily certain administrative costs). The Company disputes that marginal cost of service is an appropriate basis for setting non-firm rates, except to establish a floor for the least possible price that a non-firm customer should be paying. NGrid Post-Hearing Mem. at 84-85.

The Company also disputes that an embedded cost study is an appropriate basis for setting non-firm rates. An embedded cost study for non-firm customers requires judgments and assumptions about the assignment of costs that are inherently arbitrary. The embedded cost

studies produced by Company in this case demonstrate how different assumptions produce different results. NGrid Post-Hearing Mem. at 86-87; Ex. NGrid-38; Ex. NGrid-39.[12] Further, non-firm customers are not committed to the system and thus there is no assurance that costs allocated to the non-firm class will be recovered. NGrid Post-Hearing Mem. at 87.

Establishing a cost-based rate in the form of a discount off of firm service is not desirable because it will create an incentive to avoid taking firm service and does not allow for downward adjustment of the non-firm rate in the event that oil prices fall below natural gas. *Id.* The Company anticipates that a significant number of customers that migrated from non-firm to firm service in the past year would remigrate if a fixed, cost-based rate were established.[13] This would be poor ratemaking policy since it would have the effect of encouraging less use of the system. *Id.* at 88.

The Company argues that its proposed 150% cap is the best alternative for meeting the important ratemaking goals of (1) encouraging throughput regardless of the magnitude of price difference between gas and alternative fuels, (2) ensuring that firm customers receive an adequate benefit from non-firm use, (3) ensuring that non-firm pricing is fair and reasonable, and (4) ensuring that non-firm pricing does not undermine the integrity of the firm service rate or facilitate the avoidance of economical firm service. NGrid Post-Hearing Mem. at 90; Tr. 10/8/08 at 40-41, 112-115 (Czekanski); NGrid Response to Division Data Request 6-26.

Value of service pricing is not unjust or unreasonable because, with the exception of a few customers in capacity constrained areas of the system, it is the customer's choice to take non-firm service. Current non-firm pricing reflects the value to certain customers of being able

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[12] The Company's response to data request DIV 5-53 (Ex. DIV-13) calculates non-firm COSS at $1.3 million, or $0.81/decatherm.

[13] Data request DIV 6-5 and 6-6 refer to transfers from non-firm to firm service.

to opt in and opt out at any time without making a firm commitment to the gas distribution system. NGrid Post-Hearing Reply at 21. A fixed discount is flawed because if there is no possibility that the system would lose non-firm throughput – as might be the case when the price of alternative fuels is high -- there is no reason for the Company to extend a discounted price to non-firm customers. *Id.* at 22.

Division Position. The Division proposes setting rates for non-firm transportation service at a fixed discount of 20% off of the customer's otherwise applicable firm rate (to be computed by dividing the sum of the projected variable distribution charge revenue and demand charge revenue for the customer's otherwise applicable rate class by the projected annual therms of gas use for the otherwise applicable firm rate class for the rate year). The Division also proposes establishing a revenue requirement of $2.856 million for the non-firm rate class, based on the Company's November 5, 2008 revised cost of service study, and revising the proposed joint stipulation regarding revenue reconciliation for non-firm service to provide that revenue above $2.856 million is split 75/25 between firm and non-firm customers. Division Post-Hearing Reply at 7-8.

TEC-RI Position. It is unjust and unreasonable to set non-firm distribution rates to maximize revenue because the Company is a monopoly. Non-firm pricing should be based on cost of service. Witnesses for both the Company and other parties testified that, because non-firm service can be interrupted on days when system capacity is constrained, non-firm customers impose very low demand costs. As stated by the Company,

> This result occurs largely because the actual 'cost' of providing non-firm service is minimal. Since the system is constructed and maintained to ensure uninterrupted service to firm customers on a year-round basis (i.e., through the peak winter periods), distribution capacity is available in the off-peak periods for use by non-firm customers at little or no additional cost.

Ex. NGrid-16 at 5 (Czekanski Rebuttal). The Company also testified that "[w]e design rates that are expected to cover the full cost of service. So essentially the firm customers have paid for all the firm capacity that we provide and make available." Tr. 10/22/08 at 19-20 (Stavropoulos). Rhode Island Hospital's expert testified that

> The direct costs and marginal costs are the only real costs that are caused by non-firm customers because the company, in its planning, does not add capacity to its distribution system in order to serve non-firm customers.

Tr. 10/22/08 at 206 (DeMetro).

TEC-RI argues that it is reasonable to infer that the Company's proposed floor for non-firm rates ($0.10/Dth summer, $0.16/Dth winter) is a good proxy for the marginal cost of non-firm service. The Company's November 5, 2008 embedded cost of service calculation results in a unit cost of $0.92/Dth, but uses the same demand cost allocation for non-firm customers as for firm customers. This is not a fair or reasonable reflection of demand cost causation because non-firm customers are interrupted on peak demand days. Ex. DIV-49 (number of non-firm curtailments from 2004-2008). Non-firm customers should be allocated 50% of the demand costs. This results in a non-firm class cost of service of approximately $1.8 million based on the Company's estimated usage volume. TEC-RI Post-Hearing Mem. at 4-8.

A non-firm class cost of service of $1.8 million is consistent with the revenue requirement that would be associated with the estimated $9-10 million investment necessary to serve all non-firm customers as firm customers. Record Request DIV-7; TEC-RI Post Hearing Mem. at 8-9.

Non-firm transportation rates should be set at a fixed 40% discount to firm rates. This produces $1.8 million of revenue on the 3.1 million Dth of volume the Company used in its November 5, 2008 cost of service study. TEC-RI Post-Hearing Mem. at 2, 9.

The Commission issued an order over a year ago asking for a cost of service based rate for non-firm service. The Company did not comply, and the Division also has not produced a cost of service based rate. The best record evidence supports the 40% discount off of firm rates proposed by TEC-RI and Rhode Island Hospital. TEC-RI Post-Hearing Reply at 2.

Rhode Island Hospital Position. The current non-firm tariff has produced dramatic and unpredictable changes in the Hospital's energy costs and unreasonably high prices over the past two years. RIH proposes that the Commission order a modified cost of service approach that would establish non-firm pricing at a discount off of firm pricing. The discount would set non-firm prices at a level that is more representative of the historic level of revenues collected from this class. RIH Post-Hearing Mem. at 1-2, 10-12.

Non-firm customers receive service only if there is excess capacity on the distribution system. The Company has not invested in the infrastructure that would be needed to serve non-firm customers as firm customers, an estimated expense of at least $9-10 million. The value of gas service is highest when demand is greatest. Rates charged to non-firm customers should be lower than those charged firm customers to reflect the less valuable service received. Instead, they are significantly higher; 400% higher in September 2008. RIH Post-Hearing Mem. at 5-7.

Under R.I.G.L. § 39-2-1, utility rates must be just and reasonable. Current non-firm rates do not meet this requirement because they bear no relationship to either firm rates or the cost of providing non-firm delivery service. The Company's proposed cap for non-firm rates at 150% of firm rates is arbitrary and unsupported by any reasonable rationale. The Company is using a cost based method to design rates for firm customers, but not non-firm customers. *Id.* at 7-9.

The non-firm cost of service studies presented by the Company are flawed because the Company allocated the demand-related costs of serving large firm C&I customers to non-firm customers. At most, non-firm customers should be allocated 50% of the distribution system demand costs calculated by the Company. Including allocated customer and commodity costs, non-firm customers should contribute $1.8 million to cost of service. This is representative of the historic level of revenues collected from the non-firm class. Based on Exhibits NGrid 36, 38 and 39, setting non-firm rates at a 35-40% discount off of firm rates would collect at least that target amount of revenue. RIH Post-Hearing Mem. at 10-12.

RIH's proposal would not skew rates for other classes. It is based on the Company's cost of service studies showing that revenues of $1.8 million from non-firm ratepayers would be a substantial contribution to distribution costs. This amount would be credited to firm rates, as is done currently. RIH disputes that non-firm customers are not committed to using natural gas. Non-firm customers have incurred and continue to incur substantial costs to maintain the capacity to burn gas, for both economic and environmental reasons. RIH Post-Hearing Reply at 3-4.

The current non-firm tariff is unreasonable and is creating undue and unnecessary hardships for a number of the state's largest employers at a time of economic uncertainty and high unemployment. Value of service pricing is producing rates significantly above the cost of serving non-firm customers and four times higher than the approved rates for firm customers. The extreme volatility of value of service pricing also makes it unfair and unreasonable. In 2008, value of service costs for RIH and other extra large high volume customers ranged from $0.10/Dth to $2.83/Dth. RIH Post-Hearing Reply at 3. The Company's proposed cap does not yield just and reasonable rates. RIH Post-Hearing Mem. at 13-14.

RIH strongly opposes the Company's revenue neutrality stipulation, which for purposes of the DAC increases the base level of non-firm contribution to $2.8 million. If the Commission does not accept the Company's proposal to cap non-firm rates at 150% of firm rates, this could result in a continuing surcharge to firm ratepayers. RIH proposes that the Commission instead direct the Company to remove the additional $1.2 million of former non-firm revenues assumed in developing firm billing determinants and provide it as a credit to DAC, with true-ups. RIH Post-Hearing Reply at 5-7.

Silent Sherpa Position. Silent Sherpa proposes setting the non-firm tariff based on a marginal cost of service analysis. The distribution system is bought and paid for and delivered to firm ratepayers. It would be redundant to charge the non-firm ratepayers for the same service. Tr. 9/29/08 at 229 (Grasso); Tr. 10/8/08 at 174-175.

Commission Decision. The Commission finds that the current value of service pricing system for interruptible transportation service is not functioning as intended. The record reflects that value of service pricing was established to create an incentive for dual fuel customers to use natural gas at times when the relative prices of gas and oil would otherwise have tended to encourage those customers to use oil. Even when priced below the cost of fixed service, interruptible service for dual fuel customers benefited ratepayers by generating net distribution revenues that would have been foregone in the absence of the value of service pricing. Thus, value of service pricing maximized revenues for firm service customers by attracting net revenue from customers that would otherwise have used an alternative fuel. Ex. DIV-3 at 51-52 (Oliver).

In an environment where oil and gas prices are comparable, or the cost of natural gas exceeds the cost of oil on a per therm basis, value of service pricing for interruptible service

also makes sense because it can be said to recognize the quality of the service being provided to dual fuel customers. Fixed service customers are entitled to use the Company's distribution capacity at all times, to draw the volume of natural gas the customer calls for. Interruptible service customers may have their access to the distribution system suspended on short notice. Furthermore, in parts of Rhode Island, the service suspension can last most of the winter. When value of service pricing results in the cost of interruptible service being below the cost of firm service, that differential can also be rationalized by looking at the actual and potential service interruptions faced by non-firm customers.

Under the current tariff, $1.6 million of non-firm customer revenue is assumed in base rates. Non-firm revenues above $1.6 million are shared 75/25 between ratepayers and the Company. In recent years, the cost of oil has risen relative to the cost of natural gas. Value of service pricing has produced sizable marginal revenues for firm customers, as follows:

2005 – $1,200,000

2006 – $1,400,000

2007 – $1,700,000

2008 – $2,700,000

Ex. NGrid-36.

Rising oil prices, and the resulting increase in non-firm revenues, indicate that changes to the current value of service pricing are necessary and appropriate. Even the Company appears to agree that some change is necessary, as it has proposed capping the non-firm transportation tariff at 150% of the firm transportation rate. While the Company's approach has the potential benefit of limiting non-firm rate increases, while still extracting substantial non-firm revenues for the benefit of firm ratepayers, the Commission is not persuaded that this

modification of value of service pricing is sound ratemaking policy. Given the changes in energy markets and the economy since value of service pricing was introduced, it is time to move to a new approach.

The Company's proposal to cap value of service pricing at 150% of the firm rate was not supported by any financial or economic analysis, or even by any testimony explaining why the Company's proposed percentage cap is superior to a cap set at a higher or lower percentage. Accordingly, there is no evidence to suggest that the Company's proposal will maximize revenues from non-firm customers, which the Company asserts is the goal of value of service pricing.

The Commission also is not persuaded by the Company's arguments that a cost of service-based alternative pricing mechanism is too complex, and requires too many assumptions about non-firm costs and usage, to be workable. It is reasonable to assume that the Company has the expertise and experience with non-firm customers in Rhode Island to make educated calculations decisions regarding likely expenses and revenues. The Company presumably made those kinds of calculations and decisions before agreeing to include $1.6 million of non-firm revenues in base rates under the current tariff. Furthermore, the record reflects that the Company's New York affiliate offers non-firm service priced at 100% of the firm tariff rate. Tr. 10/08/08 at 112 (Czekanski). There is no reason to think that the Company could not implement a similar approach here in Rhode Island.

TEC-RI and Rhode Island Hospital argue that the Commission should order non-firm rates be set at a 40% discount off of firm rates. They assert that this level of discount will generate non-firm revenues in line with "historical" levels, and sufficient to cover the estimated non-firm costs of service reflected in the Company's cost of service study marked as an exhibit

during the hearings. Setting non-firm rates at a discount off of firm rates would, in their view, be a fair recognition of the fact that firm customers are assured of service year round, while non-firm customers can have their service interrupted, often for substantial periods. TEC-RI and Rhode Island Hospital also see setting non-firm rates at a fixed discount off of firm service as a way of reducing the recent volatility of non-firm pricing, which they assert makes it difficult for large Rhode Island employers to budget for energy costs.

The Commission agrees that price stability is generally desirable, and that setting the price of non-firm service as a fixed percentage of the price of firm service is a fair and reasonable methodology. For several reasons, however, the Commission does not agree that a 40% discount off of firm rates is appropriate. First, the cost of service studies submitted by the Company during the hearings were criticized by the Division. Therefore, the Commission finds that these studies, without more, are not a sufficient basis to set a non-firm discount off of firm pricing. Second, evidence presented at the hearings indicated that substantial numbers of non-firm customers have migrated to firm service in recent months. Pricing non-firm service at too deep a discount off of firm service may encourage not only the migration of these customers back to non-firm service, but additional switching by firm customers who find a 40% discount off of the cost of firm service economically attractive. This could have the undesirable effect for firm ratepayers of discouraging use of the distribution system. Third, while the Commission agrees that in some ways the quality of non-firm service is inferior to the quality of firm service – because service interruptions are allowed – the record reflects that non-firm customers can and do switch back and forth between alternative fuels to take advantage of price and demand changes. This ability to switch back and forth, without being committed to the natural gas distribution system in the same way as a firm customer, has a value to the non-firm customer that

offsets the disadvantage of potential service interruptions. For all of these reasons, the Commission adopts the Division's recommendation that non-firm service should be priced at a 20% discount off of firm pricing.

On November 5, 2008, the Company and the Division entered into a stipulation to address the potential revenue effects of the Commission's decision on this issue. NGrid Post-Hearing Mem. at 90; Division Post-Hearing Mem. at 37. The stipulation created a mechanism to account for the various possible migrations of customers between firm and non-firm service, depending on how rates for non-firm service are ultimately established, in order to assure revenue neutrality for customers and the Company. Going forward, non-firm distribution revenues will be determined by combining revenues (exclusive of gross earning tax) from the customers identified in the stipulation plus margins received from non-firm special contracts and new non-firm customers taking non-firm service after that date. For the period ending June 30, 2009, the Company will calculate the total non-firm transportation margins for the eight month period ending June 30. If the total non-firm margins are greater than $1,879,800 during that period, firm rate payers will receive credit for the excess through the DAC. If the total is less than $1,879,800, firm ratepayers will make up the difference through the DAC. For years ending June 30, 2010 and after, the break point for DAC credit will be $2,816,000. NGrid Post-Hearing Mem. at 90-92. The Commission approves the stipulation.

2. Sharing of Non-Firm Revenues.

Under the existing tariff, seventy-five percent of non-firm revenues above $1.6 million are credited to the ratepayers; the other 25% are retained by the Company. In the year ending June 30, 2008, firm customers received $2,884,688 over and above the $1.6 million built into the revenue requirement, for a total firm customer benefit of $4,484,688. Ex. PUC-7 (NGrid Response to Data Request COMM 3-9). The Company's 25% share for the same period

amounted to $961,563. Since 2003, the Company has retained a total of $2,628,300 of non-firm margin. *Id.*

Company Position. The Company proposed retaining the revenue split.

Division Position. The Division objected to retaining the revenue split. Ex. DIV-3 at 64 (Oliver). The Division argued that while value of service pricing was originally designed to encourage maximization of revenues from non-firm customers with access to competitively priced alternative fuels, that basis no longer exists after industry restructuring. Ex. DIV-3 at 51, 62-63 (Oliver). The Division argued that the Company's retention of this margin does not affect its pricing of non-firm service, or the behavior of non-firm customers. Division Post-Hearing Mem. at 38-39. The Division further argued that it is not reasonable for the Company to continue sharing the benefit of non-firm margins above $1.6 million, while ratepayers absorb all of the risk of returns below that level. *Id.* at 39.

Commission Decision. The Commission finds that in light of its decision to fix non-firm prices at a 20% discount off of firm prices, there is no longer any reason to offer the Company a share of non-firm revenues as an incentive to maximize those revenues. The Company's proposed revenue split is denied.

3. Lock In Period.

The Company proposed enlarging the time for non-firm transportation customers to lock in service prior to the beginning of a month from five to ten days. The Commission approves this proposed change.

4. Flexible Firm Service.

The Company proposed Flexible Firm Service, a firm transportation service based on negotiated, individual service agreements with dual-fuel C&I customers with usage above 150,000 therms. Ex. NGrid-15 at 21 (Czekanski). The Division opposed the proposal, citing a

lack of detail and the possible inequality of bargaining strength between the Company and a non-firm customer. Division Post-Hearing Mem. at 40; Ex. DIV-3 at 62 (Oliver). The Commission agrees that the proposed Flexible Firm Service lacks sufficient detail, and therefore declines to approve it at this time.

5. Non-Firm Sales Service Tariff.

The Company proposed eliminating non-firm sales service. Ex. NGrid-15 at 22 (Czekanski). TEC-RI proposed that the Company retain the non-firm sales tariff until the Company determines that no current customer under that tariff will be harmed if it is eliminated. TEC-RI Post-Hearing Mem. at 2. The Commission has not been presented with sufficient evidence to determine the full implications of eliminating non-firm sales service, as proposed. The Company's request to eliminate non-firm sales service is therefore denied.

G. Firm Service Rates

The Company proposed raising customer charges for residential customers from $9 to $16, and proposed increases for commercial and industrial customers (excluding Extra Large C&I) as well. The overall increase in distribution revenue requested by the Company is 15.95%. Proposed increases for certain classes range from 46.7% to over 114%. Division Post-Hearing Mem. at 43; Ex. DIV-3 at 45 (Oliver).

The Division objected to the proposed increases in customer charges, arguing that violate the ratemaking principles of gradualism, continuity and avoidance of rate shock. The Division proposes that no class should receive increases in customer and demand charges exceeding the greater of 33% or the class average increase. Tr. 8/27/08 at 182; Division Post-Hearing Mem. at 43.

The Commission finds that the proposed increases in customer and demand charges are excessive in comparison to the proposed increase in the Company's distribution

revenue requirement. The Commission approves the Division's recommendation that no class should receive increases in customer and demand charges exceeding the greater of 33% or the class average increase.[14]

H. Other Rate Design Issues

1. Consolidation of Gas Cost Rate Charges.

The Company proposed to reduce the number of Gas Cost Recovery rates from six to two. The Company asserts that this change will simplify the GCR calculations and associated monthly reporting of deferred gas cost account balances. NGrid Post-Hearing Brief at 58. The Division supports the Company's proposal, concluding that it would have no significant adverse impacts. Ex. DIV-3 at 73 (Oliver). TEC-RI opposes this change as a step away from cost of service pricing. TEC-RI believes that it could increase the GCR rates for certain classes by $0.10 /Dth or more, which translates into approximately $2.3 million. TEC-RI Post-Hearing Mem at 23-24.

The Commission finds that reducing the number of gas cost recovery rates will simplify the calculations and reporting and is in the best interest of ratepayers. The Commission approves the Company's proposed consolidation of six gas cost recovery rates to two rates.

2. DAC Adjustments

The Company proposed several changes to the Distribution Adjustment Clause to reflect other tariff changes requested by the Company in its filing. The Commission approves DAC cost recovery mechanisms consistent with its rulings set forth above for the Company's Accelerated Replacement Program and pension and PBOP expenses. The Commission also approves elimination of the Consolidation Mitigation and ERI adjustment. The other DAC

[14] Commissioner Bray dissents from this portion of the Commission's decision and opposes any increase in the fixed customer charge for reasons stated on the record at the November 24, 2008 Open Meeting. Tr. 11/24/08 at 99-101.

adjustments proposed by the Company are denied as moot in light of the Commission's rulings on decoupling and recovery of gas cost related bad debt. TEC-RI's request to modify the DAC mechanism to allocate DAC costs and credits to rate classes based on class revenues (as a proxy for cost of service allocation) instead of through a volumetric charge is denied.

3. Three Year Rate Plan Proposal.

The Company proposed an alternative three year rate plan. The plan would phase in rate increases approved in this proceeding. The Division opposed the Company's alternative three year plan, arguing that (1) it is less beneficial if the Company's revenue proposal is reduced as recommended by the Division, (2) it is difficult to forecast revenue requirements for the two years after the rate year with any degree of certainty, (3) incorporating Commission modifications to the Company's proposed revenue requirement over three years is complex, and (4) the proposed three year plan would generate approximately $23 million of revenues in excess of the revenues produced by the alternative request for a one time increase of $20 million. Division Post-Hearing Mem. at 34-35.

The Commission finds that the approved distribution revenue increase of approximately $13 million is less burdensome to ratepayers than the Company's initial $20 million request. The Commission further finds that the additional cost and complexity of phasing in the increased revenue requirement over three years outweighs the benefits of a phase in for ratepayers. The Commission declines to approve the Company's alternative three year rate plan.

Accordingly, it is

(19563) ORDERED:

Decoupling

1. Revenue Decoupling Mechanism. The Company's proposed revenue decoupling mechanism for the residential non-heating, residential heating, small C&I and medium C&I rate classes, under which the surplus above or shortfall below target revenue per customer would be credited or collected through an annual adjustment of the DAC, is denied;

Revenue Requirement Issues

2. Revenue Requirement. A rate year revenue requirement of $139,266,486 is approved, representing a $13,659,773 (10.88%) increase over the test year of $125,606,713.[15]

3. Capital Structure. The Company's proposed capital structure for ratemaking purposes of 47.71% equity, 40.63% long-term debt and 11.66% short-term debt is approved;

4. Return on Equity. The Company's proposed return on equity of 11.50% is denied. The Company shall be allowed a return on equity of 10.50% for its Rhode Island operations;

5. Size of Rate Base. The Company's proposed rate base of $285,241,458 is approved, provided that, in the event that the projected capital spending does not occur prior to the end of the rate year, the Company shall notify the Division and

[15] In response to the Commission's open meeting ruling on November 24, 2008, the Company submitted a Compliance Tariff Filing consistent with the approved revenue requirement. The Commission approved the filing on December 1, 2008. Order No. 19528 (issued January 8, 2009). A copy of Compliance Tariff Filing, Schedule NG-Compliance MDL-1, page 1 of 2 and Schedule NG-Compliance RD-1 is attached hereto as Appendix A.

make an appropriate adjustment to reflect the actual lower amount of actual plant in service;

Operating Expenses (Cost of Service)

6. Health Care Costs. The Company's proposed rate year medical and dental costs of $4,614,616 shall be reduced by $907,456, to $3,707,150;

7. FAS 112 Expense. The Company's proposed FAS 112 expense – relating to post-employment benefits other than pension – of $740,000 for FY 2009 is approved;

8. Synergy Savings – Southern Union Merger. The Company's proposed $1,054,609 synergy saving from the Company's August 2006 acquisition of the Rhode Island operations of New England Gas Company from Southern Union is denied;

9. Synergy Savings – KeySpan Merger. The stipulation between the Company and the Division relating to synergy savings resulting from the Company's August 2007 merger with KeySpan Corporation is approved. A base rate revenue credit of $2.45 million shall be included to reflect the ratepayers' 50% share of projected merger synergies net of costs to achieve. The Company shall be allowed to include its $2.45 million share of projected merger synergies in future rate cases, and to reflect its share of savings in annual earnings reports filed with the Commission for earnings sharing purposes, to the extent permitted by the stipulation. The Company's request for permission to create a regulatory asset in accordance with FAS 71 is approved;

10. Gas Marketing Program. The Company's proposal to include $1,377,000 in the base revenue requirement for a Gas Marketing Program is denied;

11. Uncollectible Expenses. The stipulation between the Company and the Division to reduce the Company's proposed uncollectible accounts receivable expense of $3,594,522 by $150,000 is approved;

12. Rate Case Expense. The Company's total rate case expenses of $1,348,443 (including Company expenses of $884,481, Division expenses of $113,075, and Commission expenses of $350,887) are approved. The Company shall be allowed to recover these expenses amortized over a three year period, or $449,481 per year;

13. Encroachment Expenses. The Company's proposed $1,054,000 for operation and maintenance expenses relating to public works and third party encroachment is denied. Encroachment expenses of $298,000 are approved;

14. Distribution Maintenance. The Company's proposed distribution maintenance expenses shall be reduced by $539,000, to $16,265,000;

Revenue Reconciliation Proposals

15. Accelerated Capital Replacement Program. The Company's proposed Accelerated Replacement Program to increase the annual replacement of distribution mains and remove high pressure inside services is approved, subject to the modifications recommended by the Division. Beginning in January 2009, the Company will submit a proposed implementation schedule to the Division each January for comment, and secure Commission approval. The Company will also submit a reconciliation report for each fiscal year. The first ARP reconciliation report for the 12 months ending March 31, 2009 will be submitted by May 15, 2009 for a rate adjustment effective July 1, 2009. The ARP will

entitle the Company to a rate adjustment only to the extent of the capital cost that is incremental to the amount included in base rates in this proceeding.

16. Gas-Supply Related Bad Debt Cost. The Company's proposed bad debt ratio of 2.46% for base rates is approved. The Company's proposed gas cost related bad debt reconciling mechanism is denied;

17. Reconciliation of Pension and PBOP. The Company's proposed annual reconciliation mechanism for pension and PBOP (post-retirement benefits other than pension) expenses is approved;

Low Income Discount

18. 10% Low Income Discount. The Company's proposed 10% discount of off Commission-approved customer and distribution charges for low income residential heating and non-heating customers eligible for LIHEAP assistance is approved. The discount shall be collected from other ratepayers based on consumption, as proposed by the Company;

Non-Firm Tariff Issues

19. Pricing for Non-Firm Transportation Customers. The Company's proposed cap on non-firm transportation rates at 150% of firm rates is denied. Non-firm transportation rates shall be set by the Company at a 20% discount off of firm customer rates. The Company's proposed sharing of non-firm revenues above $1.6 million is denied. The November 5, 2008 stipulation between the Company and the Division creating a mechanism to account for the various possible migrations of customers between firm and non-firm service is approved;

20. Lock In Period. The Company's proposal to enlarge the time for non-firm transportation customers to lock in service prior to the beginning of a month from five (5) to ten (10) days is approved;

21. Flexible Firm Service. The Company's proposal to establish a flexible firm transportation service is denied;

22. Non-Firm Sales Service. The Company's proposal to eliminate non-firm sales service is denied;

Firm Service Rates

23. Firm Service Base Charge. The Company's proposed increases in customer and demand charges shall be modified such that no class of ratepayers shall receive increases in customer and demand charges exceeding the greater of 33% or the class average increase;

Other Rate Design Issues

24. Consolidation of Gas Cost Recovery Rates. The Company's proposed consolidation of gas cost recovery rates from six rates to two rates is approved;

25. DAC Adjustments. The Company's proposed DAC cost recovery mechanisms for the Company's Accelerated Capital Replacement Program and pension and PBOP expense reconciliation are approved. The proposed elimination of the Consolidation Mitigation and ERI adjustment is approved. Other DAC adjustments proposed by the Company and TEC-RI are denied;

26. Three Year Rate Plan. The Company's proposed alternative three year rate plan is denied;

27. The Company is further ordered to comply with the reporting requirements and all other findings and directives contained in this Decision and Order.

EFFECTIVE AT WARWICK, RHODE ISLAND, PURSUANT TO AN OPEN MEETING DECISION OF THE COMMISSION ON NOVEMBER 24, 2008. WRITTEN ORDER ISSUED JANUARY 29, 2009.

PUBLIC UTILITIES COMMISSION

Elia Germani, Chairman

Robert Holbrook, Commissioner

Mary E. Bray, Commissioner

APPENDIX A

National Grid - RI Gas
Approved Revenue Requirement
Commission Open Meeting - November 24, 2008

			Decision Matrix Item
1	Co Rebuttal Position	$18,455,310	
2	Health care Adjust	(907,456)	5
3	FAS 112	740,000	6
4	SU Synergy Savings	(896,971)	7
5	SU CTA Amortization	(157,637)	7
6	Gas Marketing	(1,377,000)	9
7	Rate Case Expense (see page 2 of 2)	183,731	11
8	Low Income Uncollectible Adj	(150,000)	10
9	Pre-tax Return @ 10.50% ROE (5.01% - 5.49% * 286,031,702) /.65	(2,112,234)	2, 3 & 4
10	Rev Req Adjustment subtotal (sum of Lines 1 through 9)	(4,677,567)	
11	Bad Debt impact ((Line 10 / .9754) - Line 11)	(117,970)	
12	Total Revenue Requirement (Line 1 plus lines 10 & 11)	$13,659,773	

NationalGrid RI
Docket No.3943
Proposed Revenue Spread - Compliance

Line No.	Rate Schedule	Current Distribution Revenue	Proposed Increase	Proposed Distr. Rev. before LI Discount	Percentage Increase	Low Income Full Rate Reallocation	Low Income Discount Revenue $ 792,453	Total Proposed Distribution Revenue
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
1	Residential Non-Heat	$ 5,133,293	$ 781,903	$ 5,915,196	15.23%	$ (485,600)	$ 12,037	$ 5,441,633
2	Residential Non-Heat Discount	-	-	-	0.00%	485,600	(48,565)	437,035
3	Residential Heat	82,164,785	8,939,534	91,104,319	10.88%	(7,439,952)	379,512	84,043,878
4	Residential Heat Discount	-	-	-	0.00%	7,439,952	(743,888)	6,696,064
5	Small C/I	10,491,164	1,426,798	11,917,962	13.60%		54,238	11,972,200
6	Medium C/I	14,650,241	1,155,611	15,805,852	7.89%		120,912	15,926,764
7	Large Low	6,730,933	530,936	7,261,869	7.89%		60,898	7,322,767
8	Large High	1,812,681	172,370	1,985,051	9.51%		23,720	2,008,771
9	X-Large Low	1,108,782	156,826	1,265,608	14.14%		27,671	1,293,279
10	X-Large High	3,473,673	491,316	3,964,989	14.14%		113,465	4,078,454
11	NGV	22,738	2,474	25,212	10.88%			25,212
12	Gas Lights	18,423	2,004	20,427	10.88%			20,427
13	Total	$ 125,606,713	$ 13,659,773	$ 139,266,486	10.88%	$ -	$ 0	$ 139,266,486
14	Percent Increase		10.88%					

ATTACHMENT D

COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

AT RICHMOND, DECEMBER 23, 2008

2008 DEC 23 P 1:09

APPLICATION OF

VIRGINIA NATURAL GAS, INC.

CASE NO. PUE-2008-00060

For approval to implement a natural gas conservation and ratemaking efficiency plan including a decoupling mechanism and to record accounting entries associated with such mechanism

ORDER APPROVING NATURAL GAS
CONSERVATION AND RATEMAKING EFFICIENCY PLAN

On July 3, 2008, Virginia Natural Gas, Inc. ("VNG" or "Company"), filed with the State Corporation Commission ("Commission") an Application pursuant to the recently enacted Natural Gas Conservation and Ratemaking Efficiency Act ("Act"), § 56-600 *et seq.* of the Code of Virginia ("Code"), seeking approval to implement a natural gas conservation and ratemaking efficiency plan, which includes a decoupling mechanism, and to record accounting entries associated with such mechanism.

As set forth in the Application, the Company's proposed conservation and ratemaking efficiency plan has two principal components: (i) an Energy Conservation Plan ("ECP") to promote conservation and efficiency; and (ii) a Revenue Normalization Adjustment, Rider D ("RNA Rider" or "Rider"), which is a natural gas decoupling mechanism that provides for a sales adjustment to customers' monthly bills. The Application seeks: (1) approval of the ECP and RNA Rider effective January 1, 2009; (2) approval to capitalize the program costs (including capital costs) and to defer such costs pending the appropriate cost of service treatment, including recovery in rates, until the expiration of the Company's performance-based regulation plan

("PBR Plan") period;[1] and (3) authority to begin recording accounting entries associated with the RNA Rider decoupling mechanism effective January 1, 2009.

VNG states in the Application that its proposal does not result in a shift in the annualized allowed distribution revenue between any rate classes and maintains the non-gas revenue per customer within the rate classes established in the Company's PBR Plan. Over the initial three-year term, the Company proposes to spend $7.5 million in these programs (including the cost of capital). For that expenditure, the Company asserts that its customers can save $39.5 million over a 10-year period.[2]

The Company asserts that its proposed decoupling mechanism breaks the link between the volume of sales and the recovery of fixed costs and allows for an increased focus by local distribution companies on energy efficiency and conservation measures. Specifically, the RNA Rider is designed to separate revenues from throughput, enabling VNG to mitigate the impact of declining customer usage and to promote energy efficiency and conservation while recovering its fixed costs. According to VNG, widespread conservation would diminish gas demand and, if significant enough, could dampen natural gas commodity prices. For individual customers, the Application states that any lowering of commodity volumes consumed will result in cost avoidance.

As set forth in the Application, the Company's ECP proposal included the following energy conservation initiatives:

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[1] The Commission approved VNG's PBR Plan in 2006. *See Application of Virginia Natural Gas, Inc., For approval of a performance based rate regulation methodology pursuant to Virginia Code § 56-235.6*, and *General Rate Case Filing of Virginia Natural Gas, Inc., For investigation of justness and reasonableness of current rates, charges, and terms and conditions of service in compliance with prior Commission Order*, Case Nos. PUE-2005-00057 and PUE-2005-00062, 2006 SCC Ann. Rept. 341 (July 24, 2006) ("PBR and Rate Case Order").

[2] *See* Exh. 2 (Gidley direct) at 6.

- *Seasonal Check-Up Program*: $25 customer incentive for check-up or credit toward a programmable thermostat; recommended 21-point inspection and filter examination;

- *Low-Income Home Weatherization Program*: Individual home weatherization at no cost to qualified individuals; $1,650 per home; program to be administered in partnership with current providers of low-income weatherization programs;

- *Energy Efficient Tank Water Heater Program*: $250 incentive; installation of a tank-style natural gas water heater with an energy factor of 0.62 or greater;

- *Tankless Water Heater Program*: $500 incentive; installation of a tankless natural gas water heater with an energy factor of 0.82 or greater;

- *Space Heating Program*: $500 incentive; installation of a 90%+ Efficient Natural Gas Furnace;

- *Pilot ENERGY STAR® Residential New Construction Program*: Natural gas water heater and natural gas furnace incentives plus a $250 incentive to be applied against the cost of the ENERGY STAR® inspections, testing, and modeling; a pilot program to encourage the installation of highly energy efficient ENERGY STAR® rated equipment in residential new construction rather than the standard less-costly and less-efficient equipment;

- *Community Outreach and Customer Education Program*: A broad-based energy conservation education program specifically related to each of the above programs and directed at VNG's customers.[3]

The Company allocates the annual program costs among the above programs and requests "the ability to be flexible and transfer funds from one component to another if it determines that would be more effective or if participation in one of the components is greater than anticipated, ..."[4] The annual program costs also include "$8,000 for the administrative cost related to the processing of the incentive-related payments," and the Company proposes "to

[3] Exh. 5 (France direct), Attach. CJF-1.

[4] Exh. 6 (Hickerson direct) at 6.

defer the cost related to the annual independent verification of the net benefits . . . as required by the new legislation, and other incremental ECP costs[, which] are not expected to exceed $25,000."[5] Finally, the Application requests authority to capitalize the program costs (including capital costs) and to defer such costs pending the appropriate cost of service treatment, including recovery in rates, until the expiration of VNG's PBR Plan period on August 1, 2011, during which time the Company's base rates are frozen pursuant to the Commission's decision in Case Nos. PUE-2005-00057 and PUE-2005-00062.

On July 14, 2008, the Commission issued an Order for Notice and Hearing that, among other things, directed the Company to provide notice of its Application, established a procedural schedule for this case, and scheduled a public hearing to receive testimony from members of the public and evidence on the Application. The Commission subsequently extended the procedural schedule in response to a motion filed by the Office of the Attorney General's Division of Consumer Counsel ("Consumer Counsel"). The Commission received written comments from: the New Kent County Board of Supervisors (opposing a rate increase); the Natural Resources Defense Council ("NRDC") (supporting efforts to implement decoupling and energy efficiency programs); and the Virginia Interfaith Center for Public Policy ("Center") (supporting the Application).

On October 14, 2008, the Commission convened a public hearing for the purpose of receiving testimony from public witnesses, and the following testified as public witnesses thereat: Brandi Colander on behalf of NRDC; and Rev. C. Douglas Smith on behalf of the Center.

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[5] *Id.*

On October 22, 2008, VNG filed a Proposed Stipulation and Recommendation between VNG and Consumer Counsel.

On October 23, 2008, the Commission convened a public evidentiary at which the following participated and presented one or more witnesses: VNG; Consumer Counsel; and the Commission's Staff ("Staff").

On October 29, 2008, VNG filed a Proposed Stipulation and Recommendation (REVISED) ("Revised Stipulation") between VNG and Consumer Counsel, as had been discussed during the October 23 hearing. The Revised Stipulation includes the following modifications to the Company's proposed conservation and ratemaking efficiency plan:

1. The VNG Community Outreach and Customer Education Program will include, through VNG bill inserts and/or other media materials, energy efficiency and conservation educational information targeted to all VNG residential customers throughout each year of the [ECP]. The Company will also make available to every VNG residential customer a $4.00 coupon each year for replacement of an air filter through a supplier with whom VNG will partner (*e.g.*, Home Depot, Sears, *etc.*), with the expectation of attaining high customer participation. The total cost of all (ECP) programs will not change. Program costs for the air filter coupon will be included as part of the Community Outreach and Customer Education spending.

2. An Energy Conservation and Efficiency Advisory Group will be formed (the composition of which will be mutually agreed upon by VNG, the Commission and Consumer Counsel), which will meet periodically to evaluate, review, and recommend adjustments to VNG's conservation and energy efficiency programs (*i.e.*, ECP), including items such as, but not limited to: evaluating results, customer behavior and additional needs of the customers; reviewing program participation, public perception, attendance at outreach meetings, and participation on the Company's website; and recommending new conservation and efficiency technology and hotline telephone numbers to provide conservation advice, new and revised conservation education programs, forums, potential partnerships that should be explored for increased outreach, and change in media/messaging based on review of results.

3. The Company will also implement a programmable thermostat program in which the Company will partner with a supplier to make thermostats available to a group of customers at wholesale prices by taking advantage of bulk purchasing. The Company will provide $25 per customer towards the purchase of these thermostats. The Company will spend $125,000 on this program. The total cost of all (ECP) programs will not change. Program costs will be reallocated as shown on Exhibit A [to the Revised Stipulation]. In addition, as described in the seasonal check up program included in VNG's Application, customers would still be eligible to receive $25 toward the purchase of a programmable thermostat if they choose to purchase a model other than what the Company provides under the program described in this paragraph of the Stipulation.

4. In compliance with the Va. Code § 56-602, VNG will, on an annual basis, file an annual report with Commission Staff showing the year-over-year weather-normalized use of natural gas on an average customer basis for the Residential Customer Class and an independently-verified report of the economic benefits created by the conservation and energy efficiency programs (*i.e.*, ECP). Such report will include the findings and recommendations of the Energy Conservation and Efficiency Advisory Group, including cost benefit analysis of the conservation and energy efficiency programs (*i.e.*, ECP), participation rates, an effectiveness test comparing results to a non-participating control group, and expected program benefits for the next program year.

5. The [plan] shall be limited to an initial period of not more than 3 years from the effective date approved by the Commission. If VNG desires to continue the [plan] after the 3-year period, it will be required to seek further authority to do so from the Commission.

6. Nothing herein shall prevent the Energy Conservation and Efficiency Advisory Group from proposing mutually agreeable changes to the ECP within the 3-year period.

7. The Company shall not earn a return or recover any form of carrying costs on deferred incremental costs incurred within the 3-year period for its conservation and energy efficiency programs. The undersigned parties agree that the Company's proposal as modified herein complies with the definition "Cost-effective conservation and energy efficiency program" for purposes of recovery of deferred incremental costs pursuant to Va. Code

> § 56-602.D. The ECP costs, excluding carrying costs, shall be included in VNG's next rate proceeding as an expense for recovery over an amortized period. The deferred ECP costs will not be classified as rate base in VNG's next rate proceeding.[6]

On November 26, 2008, VNG, Consumer Counsel, and Staff filed post-hearing briefs.

NOW THE COMMISSION, having considered this matter, is of the opinion and finds that a conservation ratemaking and efficiency plan as permitted by § 56-600 *et seq.* of the Code is approved as set forth in this Final Order. We approve the Revised Stipulation entered into by VNG and Consumer Counsel and, consistent with the Revised Stipulation, we (1) direct a reallocation of the program costs among the ECP programs to ensure compliance with the Act, and (2) do not increase the *total* cost to the Company of all ECP programs.

This is the first case under the Act. We find that the conservation ratemaking and efficiency plan, as defined by the provisions of the Revised Stipulation and the requirements of this Final Order ("Plan"), satisfies the statutory requirements of the Act.

Code of Virginia

Section 56-602 A of the Code provides in part as follows:

> Notwithstanding any provision of law to the contrary, each natural gas utility shall have the option to file a conservation and ratemaking efficiency plan as provided in this chapter. Such a plan may include one or more residential, small commercial, or small general service classes, but shall not apply to large commercial or large industrial classes of customers. Such plan shall include: (i) a normalization component that removes the effect of weather from the determination of conservation and energy efficiency results; (ii) a decoupling mechanism; (iii) one or more cost-effective conservation and energy efficiency programs; (iv) provisions to address the needs of low-income or low-usage residential customers; and (v) provisions to ensure that the rates and service to non-participating classes of customers are not adversely impacted. Such plan may also include provisions for phased or targeted

[6] Exh. 3 (Revised Stipulation) at 1-4.

implementation of rate or tariff design changes, if any, or conservation and energy efficiency programs.

Section 56-602 B of the Code directs in part as follows:

> The Commission shall approve or deny, within 180 days, a natural gas utility's initial application for any revenue-neutral conservation and ratemaking efficiency plan that allocates annual per-customer fixed costs on an intra-class basis in reliance upon a revenue study or class cost of service study supporting the rates in effect at the time the plan is filed. A plan filed pursuant to this subsection shall not require the filing of rate case schedules. . . . The Commission shall approve such a plan . . . if it finds that the plan's . . . proposed decoupling mechanism is revenue-neutral and is otherwise consistent with this chapter.

Section 56-600 of the Code includes definitions of some of the terms used above, including the following:

> '*Allowed distribution revenue*' means the average annual, weather-normalized, nongas commodity revenue per customer associated with the rates in effect as adopted in the applicable utility's last Commission-approved rate case or performance-based regulation plan, multiplied by the average number of customers served.
>
> '*Conservation and ratemaking efficiency plan*' means a plan filed by a natural gas utility pursuant to this chapter that includes a decoupling mechanism.
>
> '*Cost-effective conservation and energy efficiency program*' means a program approved by the Commission that is designed to decrease the average customer's annual, weather-normalized consumption or total gas bill, for gas and nongas elements combined, or avoid energy costs or consumption the customer may otherwise have incurred, and is determined by the Commission to be cost-effective after analyzing such program using the Total Resource Cost Test, the Societal Test, the Program Administrator Test, the Participant Test, the Rate Impact Measure Test, and any other test the Commission reasonably deems appropriate. The Commission may determine the weight to be given to a test. Without limitation, rate designs or rate mechanisms, customer education, customer incentives, and weatherization programs are examples of conservation and energy efficiency programs that the Commission may consider.

> '*Decoupling mechanism*' means a rate, tariff design or mechanism that decouples the recovery of a utility's allowed distribution revenue from the level of consumption of natural gas by its customers, including (i) a mechanism that adjusts actual nongas distribution revenues per customer to allowed distribution revenues per customer, such as a sales adjustment clause, (ii) rate design changes that substantially align the percentage of fixed charge revenue recovery with the percentage of the utility's fixed costs, such as straight fixed variable rates, provided such mechanism includes a substantial demand component based on a customer's peak usage, or (iii) a combination of clauses (i) and (ii) that substantially decreases the relative amount of nongas distribution revenue affected by changes in per customer consumption of gas. . . .
>
> '*Revenue-neutral*' means a change in a rate, tariff design or mechanism as a component of a conservation and ratemaking efficiency plan that does not shift annualized allowed distribution revenue between customer classes, and does not increase or decrease the utility's average, weather-normalized nongas utility revenue per customer for any given rate class by more than 0.25 percent when compared to (i) the rate, tariff design or mechanism in effect at the time a conservation and ratemaking efficiency plan is filed pursuant to this chapter or (ii) the allocation of costs approved by the Commission in a rate case using the cost of service methodology set forth in § 56-235.2 or a performance-based regulation plan authorized by § 56-235.6, where a plan is filed in conjunction with such case.

Section 56-602 E of the Code mandates as follows:

> The Commission shall require every natural gas utility operating under a conservation and ratemaking efficiency plan approved pursuant to this chapter to file annual reports showing the year over year weather-normalized use of natural gas on an average customer basis, by customer class, as well as the incremental, independently verified net economic benefits created by the utility's cost-effective conservation and energy-efficiency programs during the previous year.

Conservation and Ratemaking Efficiency Plan

Both parts of the Plan - *i.e.*, the ECP and the RNA Rider - apply only to VNG's residential customers served under Rate Schedule 1 (Residential Firm Gas Sales Service) and

Rate Schedule 3 (Residential Air Conditioning Firm Gas Sales Service).[7] Accordingly, the Plan complies with the requirement in § 56-602 A of the Code that "[s]uch a plan may include one or more residential, small commercial, or small general service classes, but shall not apply to large commercial or large industrial classes of customers."

Conservation and energy efficiency programs

As noted above, the first principal component of the Plan is the ECP, which contains the Company's proposed conservation and energy efficiency programs.

Normalization component

As required by § 56-602 A (i) of the Code, the Plan includes "a normalization component that removes the effect of weather from the determination of conservation and energy efficiency results." VNG explains as follows:

> The Company will . . . compute the weatherized usage and revenue that will be used in the determination of the conservation and energy efficiency results. In addition, we will track, on an individual premise basis, the consumption and revenue for each premise that participates in any component of the ECP (the Company's initiatives to encourage conservation and efficiency). The usage and revenue associated with each of these premises will be weather normalized to allow for the effectiveness of the respective plans to be evaluated on a component-by-component basis.[8]

Low-income or low-usage residential customers

As required by § 56-602 A (iv) of the Code, the Plan includes "provisions to address the needs of low-income or low-usage residential customers." The Plan, as proposed and approved herein, includes a Low-Income Home Weatherization Program that, among other things: (1) will be administered in partnership with current providers of low-income weatherization programs;

[7] *See, e.g.*, Exh. 6 (Hickerson direct), Attach. ARH-1 at 1.

[8] Exh. 6 (Hickerson direct) at 14-15.

(2) will provide individual home weatherization at no cost to qualified individuals at a value of up to $1,646 per home; (3) will have a total program cost of $372,075; and (4) will serve at least 226 low-income households.[9]

Cost-effective conservation and energy efficiency programs

Section 56-602 A (iii) of the Code states that the Plan "shall include . . . one or more *cost-effective* conservation and energy efficiency programs" (emphasis added). As noted above, the Act includes a definition for a "cost-effective conservation and energy efficiency program."[10] That definition, among other things, requires the Commission to determine whether such program is cost-effective after analyzing the program using several named tests "and any other test the Commission reasonably deems appropriate."[11] In addition, the Act does not require that a program pass any or all of the tests and, further, provides that "[t]he Commission may determine the weight to be given to a test."[12]

In this regard, the ECP passes all the named tests except the Rate Impact Measure Test ("RIM Test").[13] The RIM Test generally measures the rate impact on residential customers that do not participate in the ECP and, thus, is sometimes referred to as the "Non-Participant Test."[14] Staff explained that, under VNG's own analysis included in its Application, approximately 96% of residential customers will be *negatively* impacted by the ECP in any given year - *i.e.*, 96%

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[9] *See, e.g.,* Exh. 5 (France direct) at 8-9; Exh. 20 (France rebuttal) at 4-5; Exh. 3 (Revised Stipulation), Exhibit A.

[10] Va. Code § 56-600.

[11] *Id.*

[12] *Id.*

[13] *See, e.g.,* VNG's November 26, 2008 post-hearing brief at 35-37; Staff's November 26, 2008 post-hearing brief at 6-8, 14-15; Consumer Counsel's November 26, 2008 post-hearing brief at 3-5.

[14] *See, e.g.,* Exh. 8 (Watkins direct) at 5-6; Exh. 14 (Walker direct) at 8.

could pay higher bills than they otherwise would have absent the ECP.[15] Indeed, Consumer Counsel explains that the ECP requires "non-participating [residential] ratepayers to pay for the monetary benefits received only by the program's participants. . . ."[16]

This disparity, however, highlights one of the ratemaking premises reflected in the Act: customers in a rate class who do not conserve (*i.e.*, assumed non-participants) may pay more in order for the Company to recoup the revenue lost from those who conserved. This policy, built into the statute, will necessarily make it difficult for many conservation programs to meet the RIM Test. Consumer Counsel explains this by noting that, under the Act, there will be "disparate impact" between participants and non-participants in a rate class, and that the Commission should determine whether such impact "is reasonable or not."[17] Thus, Consumer Counsel "*cautions* the Commission against applying the RIM Test in a manner that could result in adopting a policy that *no* conservation and energy efficiency programs as envisioned by the Act would *ever* be approved."[18]

The Act also permits the Commission to analyze the ECP using "any other test the Commission reasonably deems appropriate."[19] The results of the RIM Test highlight the limited number of residential customers that are expected to take part in the ECP as proposed in the

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[15] *See* Exh. 14 (Walker direct) at 9.

[16] Exh. 8 (Watkins direct) at 7.

[17] Consumer Counsel's November 26, 2008 post-hearing brief at 6.

[18] *Id.* (emphasis added). Although passage of the RIM Test is not a statutory prerequisite for approval, VNG (1) agrees that the Commission should not ignore the rate impact on non-participants, which VNG estimates at less than $0.72 per month, and (2) notes that the Act specifically permits "targeted" implementation of such programs. VNG's November 26, 2008 post-hearing brief at 35-36.

[19] Va. Code § 56-600.

Application. Thus, we find that it is reasonably appropriate to consider the number of customers targeted, and the type of programs that they are targeted with, as part of the ECP.[20] In this regard, we conclude as follows: (1) that for the Plan to be cost effective under the Act, the annual funds proposed by the Company should be allocated in a manner that appreciably increases the realistically possible number of participants in significant conservation measures; and (2) that this shall be accomplished by increasing the allocation of funds for the Programmable Thermostat Program resulting in a total allocation as set forth below. This reallocation of funds should, among other things, help to reduce the potential number of non-participants that will be required to pay for this Plan, but that gain no benefit thereunder.

Accordingly, the ECP shall reflect the following allocation:

Community Outreach and Customer Education Program
Annual Cost: $750,000
Incentive: --
Number of Participants: --

Programmable Thermostat Program
Annual Cost: $625,000
Incentive: $25
Number of Participants: 25,000

Low-Income Home Weatherization Program
Annual Cost: $372,075
Incentive: $1,646
Number of Participants: 226

Seasonal Check-Up Program
Annual Cost: $188,750
Incentive: $25
Number of Participants: 7,550

[20] We recognize that the Revised Stipulation, which includes a $4.00 air filter coupon (to be paid out of the funds allocated to the Community Outreach and Customer Education Program) and a Programmable Thermostat Program for 5,000 customers, should increase participation in the ECP. *See* Exh. 3 (Revised Stipulation).

Tank Water Heater Program
Annual Cost: $26,500
Incentive: $150
Number of Participants: 177

Tankless Water Heater Program
Annual Cost: $98,000
Incentive: $500
Number of Participants: 196

Space Heating Program
Annual Cost: $98,000
Incentive: $500
Number of Participants: 196

ENERGY STAR® Residential New Construction Program
Annual Cost: $5,000
Incentive: $250
Number of Participants: 20

This reallocation does not exceed the *total* cost of the ECP programs contained in the Revised Stipulation and is consistent with the Revised Stipulation. We find that, at this time, the above allocation is necessary to make the ECP "cost-effective" under the Act and to address the potential deficiencies in the Plan identified by the RIM Test. We recognize, as did VNG, that it may be reasonable to transfer funds from one program to another after gaining actual experience with the ECP, without increasing the total cost of all programs.[21] Furthermore, the Revised Stipulation provides that the Energy Conservation and Efficiency Advisory Group (created as part of the Revised Stipulation) will evaluate and recommend changes to the ECP programs during the three-year term of the Plan. Accordingly, while we direct the cost allocations set forth above at this time, we do not preclude modifications thereto after the first year of the Plan. Thus, in accordance with the Revised Stipulation, the reallocation directed herein may be reviewed by the Energy Conservation and Efficiency Advisory Group, and requests for any further

[21] *See* Exh. 6 (Hickerson direct) at 6.

reallocations of ECP program costs during the life of the Plan may be made to this Commission by that group.

Decoupling mechanism

As noted above, the second principal component of the Plan is the RNA Rider, which represents the Company's proposed decoupling mechanism under § 56-602 A (ii) of the Code. We find that the RNA Rider, which is a sales adjustment clause, complies with the specific provisions of the Act and, as required by § 56-602 B of the Code, is otherwise consistent with the provisions of the Act.

Sales adjustment clause

Staff opposed the form of the Rider, preferring that such a Rider, if any, be in the form of a change in rate design and not a sales adjustment clause.[22] This position, however, is contrary to the explicit language of the statute permitting the decoupling mechanism to take the form of a sales adjustment clause. Specifically, as permitted by the Act, the Rider is a "mechanism that decouples the recovery of a utility's allowed distribution revenue from the level of consumption of natural gas by its customers, including (i) a mechanism that adjusts actual nongas distribution revenues per customer to allowed distribution revenues per customer, such as a *sales adjustment clause*."[23]

Customer classes

As required by § 56-602 A (v) of the Code, the Plan includes "provisions to ensure that the rates and service to non-participating classes of customers are not adversely impacted." The Act describes "classes of customers" in terms of "residential, small commercial, . . . small

[22] *See, e.g.*, Tr. 233-234.

[23] Va. Code § 56-600 (emphasis added).

general service classes, [and] large commercial or large industrial classes of customers."[24] The Plan only applies to the residential class of customers, and the rates and service to "non-participating classes of customers" - *i.e.*, small commercial, small general service, large commercial, and large industrial classes - are not impacted, adversely or otherwise, by the Plan.[25]

In this regard, we reject Staff's proposition that customer classes - under the express terms of the Act - could mean something other than the residential, small commercial, small general service, large commercial, and large industrial customer classes.[26] Rather, we agree with Consumer Counsel's explanation as follows:

> The statute speaks in terms of the residential, small commercial, small general service, large commercial, and large industrial classes of customers. The entire residential class of customers - Schedules 1 and 3 - is included under VNG's proposed [Plan]. The small commercial and small general service classes are legally eligible to be included in a [Plan], but under VNG's proposed plan those classes are not included. Thus, in this instance, Consumer Counsel understands subdivision (v) to require that rates and service under VNG's [Plan] applicable to the residential class of customers not adversely impact the small commercial or small general service classes of customers, as well as the large commercial and large industrial classes of customers.[27]

Thus, contrary to Staff's suggestion, which diverges from the plain language of the Act, the Act does not permit the Commission to create subsets of classes within the residential class as identified by statute.

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[24] Va. Code § 56-602 A.

[25] *See, e.g.*, Exh. 6 (Hickerson direct) at 18.

[26] *See, e.g.*, Tr. 275-279.

[27] Consumer Counsel's November 26, 2008 post-hearing brief at 7.

Revenue-neutral

Similarly, as required by the Act's definition of "revenue-neutral," the RNA Rider "does not shift annualized allowed distribution revenue between *customer classes*."[28] No revenue is shifted between customer classes; the ECP and the Rider only apply to the residential class of customers.

Next, as also required by the Act's definition of "revenue-neutral," the RNA Rider "does not increase or decrease the utility's average, weather-normalized nongas utility revenue per customer for any given rate class by more than 0.25 percent when compared to (i) the rate, tariff design or mechanism in effect at the time a conservation and ratemaking efficiency plan is filed pursuant to this chapter."[29] As noted by VNG, the "rates in effect at the time VNG filed its Plan were adopted by the Commission in the Company's PBR Plan Proceeding."[30] Under the PBR Plan, VNG's average, weather-normalized nongas utility revenue per customer for the residential class is $223.68, and the RNA Rider is designed to ensure that such revenue per customer remains at $223.68.[31]

Staff asserts, nonetheless, that the Rider is not revenue-neutral. The RNA Rider, as required by the Act, is based on the PBR Plan that, in turn, is based on usage for the 12 months ending March 2005.[32] Staff explains that usage during that 12-month period was higher than any

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[28] Va. Code § 56-600 (emphasis added).

[29] Va. Code § 56-600. Contrary to Staff' suggestion, subsection (ii) of the definition of "revenue-neutral" in § 56-600 of the Code is inapplicable herein, because the Plan was not "filed in conjunction with" a rate case or PBR plan.

[30] VNG's November 26, 2008 post-hearing brief at 9.

[31] *See, e.g.*, Exh. 16 (Hickerson rebuttal) at 3-4; VNG's November 26, 2008 post-hearing brief at 11-12.

[32] *See, e.g.*, Exh. 14 (Walker direct) at 15.

subsequent 12-month period.[33] For example, Staff illustrates that if the RNA Rider was in effect during 2006 and 2007 - without the ECP program - VNG's revenues would have increased by over 5%; that is, customers would have paid over 5% more than they actually paid during 2006 and 2007 if the RNA Rider was in effect.[34] We must reject Staff's conclusion as a matter of law. The Act explicitly defines "revenue-neutral" as applied above, and Staff's analysis does not comply with such definition.

Efficiency targets and penalties for poor performance

VNG states that the Natural Resources Defense Council ("NRDC") "has filed comments in this proceeding supporting the Company's decoupling and conservation plan. . . ."[35] The NRDC, however, testified at the hearing that it is not familiar with the specific conservation programs proposed by VNG in its Application.[36] The NRDC also asserts that in conjunction with the benefits received by the Company through the decoupling mechanism, the Plan also should include energy "efficiency targets" for VNG and should reflect "penalties for poor performance" by VNG under the ECP.[37] Staff similarly suggests that the decoupling mechanism be linked to the amount of conservation achieved under the ECP.[38] The Company, however, asserts that "[d]ecoupling revenue should not be directly tied to conservation,"[39] and

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[33] *Id.*

[34] *See* Exh. 14 (Walker direct) at 15-16.

[35] VNG's November 26, 2008 post-hearing brief at 41.

[36] Tr. 13-14.

[37] *See, e.g.,* Tr. 10-12; NRDC's October 8, 2008 comments at 3.

[38] *See, e.g.,* Exh. 12 (Spinner direct) at 20-21; Exh. 14 (Walker direct) at 20-21.

[39] *See* VNG's November 26, 2008 post-hearing brief at 21 (typeface modified).

"[decoupling revenue to VNG] is not a reward for conservation. . . ."[40] In this regard, the Company is correct that the Act does not require the linkage recommended by the NRDC and Staff. Although the NRDC asserts that such efficiency targets and penalties for poor performance should be part of any successful decoupling program, the Act includes no provision for such penalties and does not tie the definition of "decoupling mechanism" to any amount of conservation. Accordingly, we must deny the NRDC's and Staff's recommendations in this regard.

Bills

Staff states that: (1) the RNA Rider represents VNG's "third adjustment to the bills of its residential customers;" (2) the two current adjustments are to reflect (a) normal weather (*i.e.*, a weather normalization adjustment ("WNA")), and (b) purchased gas costs; and (3) the "layering of rate adjustments can give rise to billing errors and increased customer confusion."[41]

In this regard, we note that the RNA Rider adjustment (i) is a monthly adjustment, and (ii) can represent either a credit or a surcharge to the customer's bill. Similarly, the WNA (i) is a monthly adjustment, and (ii) can represent either a credit or a surcharge to the customer's bill. Further, the Commission requires VNG to list the impact of the WNA as a separate line item on the customer's monthly bill; this provides a reasonable level of billing transparency and assists in identifying the individual bill impact of the WNA program. We likewise find that VNG shall list the impact of the RNA Rider adjustment as a separate line item on the customer's monthly bill. As with the WNA, we find that the risk of confusion from a separate line item is outweighed by the value to customers of billing transparency.

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[40] *Id.* at 22.

[41] Exh. 14 (Walker direct) at 26.

Reports

As required by § 56-602 E of the Code, VNG will file annual reports "'showing the year over year weather-normalized use of natural gas on an average customer basis, by customer class, as well as the incremental, independently verified net economic benefits created by the utility's cost-effective conservation and energy-efficiency programs during the previous year.'"[42] We further note that the Plan, as approved herein, includes the following provision:

> In compliance with the Va. Code § 56-602, VNG will, on an annual basis, file an annual report with Commission Staff showing the year-over-year weather-normalized use of natural gas on an average customer basis for the Residential Customer Class and an independently-verified report of the economic benefits created by the conservation and energy efficiency programs (*i.e.*, ECP). Such report will include the findings and recommendations of the Energy Conservation and Efficiency Advisory Group, including cost benefit analysis of the conservation and energy efficiency programs (*i.e.*, ECP), participation rates, an effectiveness test comparing results to a non-participating control group, and expected program benefits for the next program year.[43]

PBR Plan

Consumer Counsel and Staff note the potential conflict between the Plan and VNG's existing PBR Plan as approved by the Commission.[44] The Company, however, correctly points out that the Act explicitly permits VNG to implement a conservation and ratemaking efficiency plan regardless of whether the Company is operating under a Commission-approved PBR Plan.[45] Section 56-601 B of the Code provides as follows: "Natural gas utilities are authorized pursuant to this chapter to file natural gas conservation and ratemaking efficiency plans that implement

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[42] *See, e.g.,* VNG's November 26, 2008 post-hearing brief at 39-40.

[43] Exh. 3 (Revised Stipulation) at 3-4.

[44] *See, e.g.,* Exh. 8 (Watkins direct) at 15-16; Exh. 14 (Walker direct) at 16.

[45] *See* VNG's November 26, 2008 post-hearing brief at 8-9.

alternative natural gas utility rate designs and other mechanisms, in addition to . . . performance-based regulation plans authorized by § 56-235.6." Moreover, as noted above, § 56-602 A of the Act further states as follows: "Notwithstanding any provision of law to the contrary, each natural gas utility shall have the option to file a conservation and ratemaking efficiency plan as provided in this chapter." Accordingly, we find that VNG's existing PBR Plan does not stand as a legal impediment to implementation of the Plan herein.

At the same time, we must also acknowledge that the Plan will necessarily change the amount that VNG's customers otherwise would have paid for non-gas service under the PBR Plan as approved by the Commission.[46] In the PBR and Rate Case Order, the Commission found that VNG's annual revenues needed to be *reduced* by approximately $9.83 million in order for rates to be considered "just and reasonable."[47] The Commission, however, did not order a rate decrease but, rather, approved the existing PBR Plan that, among other things: (1) requires VNG to construct a pipeline from its northern system that will cross the James River/Hampton Roads Channel and tie into VNG's distribution system in Norfolk to allow for the physical flow of gas

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[46] For example, while the Commission does not currently intend to re-open the PBR Plan for further evaluation, we recognize that the PBR statute directs that the Commission may "alter, amend or revoke" a previously approved PBR Plan if it finds, among other things, that:

> (iv) the performance-based form of regulation is resulting in rates that are excessive compared to a gas utility's or electric utility's cost of service and any benefits that accrue from the performance-based plan; (v) the terms ordered by the Commission in connection with approval of a gas utility's or electric utility's implementation of a performance-based form of regulation have been violated; or (vi) the performance-based form of regulation is no longer in the public interest.

Va. Code § 56-235.6 C.

[47] *See* PBR and Rate Case Order, 2006 SCC Ann. Rept. at 347.

from the northern system to the southern system ("HRX Pipeline"); and (2) freezes VNG's non-gas rates for five years (August 1, 2006, to July 31, 2011).[48]

The Commission approved the rates in the PBR Plan[49] because we found that those rates complied with the specific requirements of the PBR statute; to wit, we found that the PBR Plan did "not result in excessive rates" under § 56-235.6 B of the Code "when compared to the benefits" to customers under the PBR Plan, which included the Company's commitment to construct the HRX Pipeline (a commitment that VNG has kept)[50] and the projected long-term cost savings to customers over the life of the HRX Pipeline.[51] Thus, having found that VNG's annual non-gas revenues should be reduced by $9.83 million, allowing non-gas rates to remain unchanged through the five-year PBR Plan period was a necessary and obviously critical component of our approval of that plan.

Indeed, in seeking approval of the PBR Plan, the Company repeatedly assured the Commission that VNG's customers would be assured of "rate certainty" for the non-gas portion of service for the five-year life of the PBR Plan.[52] The Commission relied upon such representations in approving the PBR Plan and, further, explained that rates would be reduced by

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[48] *Id.*

[49] Commissioner Jagdmann did not participate in the PBR and Rate Case Order.

[50] *See, e.g.*, VNG's November 12, 2008 Report of Action in Case No. PUE-2005-00057.

[51] *See* PBR and Rate Case Order, 2006 SCC Ann. Rept. at 349.

[52] *See, e.g.*, the following statements from VNG in Case No. PUE-2005-00057: "The PBR Plan freezes VNG's [non-gas] rates at their 1996 level until 2011. This provides continued stable rates [over the five-year PBR period] - a guarantee of 14 years of stable base rates . . ." (Application at 9); "[The five-year rate freeze] provide[s] *rate certainty* for our customers for at least five years" (January 27, 2006 Statement of VNG President Henry P. Lingenfelter at 6 (emphasis added)); "[A]ll parties to the [PBR] case have agreed to the current rates for a five-year period" (VNG's January 30, 2006 Reply at 6); and "[The five-year rate freeze] provid[es] *rate certainty* to all VNG customers for at least five years" (VNG's January 30, 2006 Reply at 4 (emphasis added)).

$9.83 million if the PBR Plan was ever withdrawn or terminated.[53] That reliance, however, apparently was misplaced since, upon implementation of the Plan, the price paid by many - if not all - residential customers for non-gas service may likely increase.

First, as discussed above, the Plan is structured so that the Company is guaranteed to recover the average, weather-normalized non-gas utility revenue per customer that is reflected in the PBR Plan. While we conclude that the RNA Rider is "revenue-neutral" as that term is defined by the Act, the Rider is by no means "revenue-neutral" in terms of its likely actual effect on individual customers. The Plan is structured so that VNG is guaranteed to recover a certain amount of revenue from the residential class, regardless of how much natural gas the class uses as a whole. This is accomplished, through the Rider, by effectively increasing rates to all members of the residential class, via a "sales adjustment" when sales volumes decline, in order to meet VNG's guaranteed revenue for that class.[54] As a result, all customers - whether or not they decrease their individual natural gas usage - end up paying more to VNG for the non-gas portion of their bills.

The Company acknowledges that, under its Plan, the bill increases to individual customers are not directly tied to any particular conservation targets or savings, such as, *e.g.*, when VNG states that "decoupling revenue [to VNG] should not be directly tied to conservation"[55] savings to customers, and "[decoupling revenue to VNG] is not a reward for

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[53] *See* PBR and Rate Case Order, 2006 SCC Ann. Rept. at 349 ("If the PBR Plan is withdrawn or terminated, and absent a subsequent rate case or performance based ratemaking methodology, VNG's rates shall be established in accordance with the revenue requirements and rate design found just and reasonable by the Commission under § 56-235.2 A of the Code in Case No. PUE-2005-00062.").

[54] Conversely, VNG asserts that customers would receive a credit under the RNA Rider if the revenue per customer exceeds that reflected in the PBR Plan. *See* Exh. 16 (Hickerson rebuttal) at 12.

[55] VNG's November 26, 2008 post-hearing brief at 21.

conservation . . . ."[56] Moreover, when VNG states that the Act "allows cost shifting on an intra-class basis,"[57] it recognizes that individual VNG residential ratepayers may pay more than they are currently paying under the PBR Plan rate structure, even if they reduce their consumption of natural gas or already use relatively little gas.

Second, and as also explained above, the RNA Rider is based on the usage and revenue reflected by the PBR Plan. This PBR Plan revenue is based on historical customer usage for the 12 months ending March 2005, and Staff explains that "there has been no single consecutive 12-month period when actual usage conditions were higher than the [RNA Rider] targets since March 2005."[58] For example, in 2006 and 2007 the average usage was less than that for the 12 months ending March 2005. As a result, if the RNA Rider was in effect during 2006 and 2007, residential customers would have seen a "sales adjustment" under the Rider in order to increase VNG's revenues. In other words, if the RNA Rider was in effect during 2006 and 2007, residential customers' bills would have been *higher* than they actually were in 2006 and 2007 under the PBR Plan - and this is without any ECP programs.[59] Thus, the implementation of the RNA Rider clearly may increase residential customers' bills from what they otherwise would have been under the PBR Plan.

VNG asserts, however, that this result from the Rider is not technically a *rate increase* but, rather, represents a *sales adjustment* as permitted by the Act. VNG claims that a "sales adjustment clause" - such as the RNA Rider - which increases a customer's bill pursuant to the Act is not the same thing as a rate increase because the "sales adjustment clause allows [VNG] to

[56] *Id.* at 22.

[57] *Id.*

[58] Exh. 14 (Walker direct) at 15.

[59] *See, e.g.*, Exh. 14 (Walker direct) at 15; Exh. 8 (Watkins direct) at 17-19.

obtain its 'allowed distribution revenue' without changing its rates."[60] While we find that VNG is technically correct in its legal interpretation of a "sales adjustment clause" under the Act, we also recognize that this technical ratemaking distinction is likely of little comfort to ratepayers. If a customer's bill goes up, calling it a *sales adjustment* – as opposed to a *rate increase* – does not change the fact that the customer's bill is higher than it otherwise would have been.[61] As a result, we must acknowledge that while customers' "rates" technically may not change as a matter of legal analysis under the Act, the actual effect of VNG's sales adjustment clause (*i.e.*, the RNA Rider) may be increases in many customers' bills versus what they would have been under the PBR Plan, which we approved in 2006 with the expectation that we were ensuring "rate certainty" as represented by VNG.

Accordingly, while we approve the Plan herein pursuant to the Act, we must acknowledge that the ultimate price that VNG's residential customers will pay for non-gas service under the Plan may be higher than the frozen rates established by the Commission in the PBR Plan. This is especially relevant at a time of economic hardship when many of VNG's customers are struggling to pay their monthly bills and may be facing tremendous uncertainty about their employment security.[62]

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[60] VNG's November 26, 2008 post-hearing brief at 17 (quoting Va. Code § 56-600). *See also id.* at 9-13.

[61] In other words, it is possible that a particular customer's bill could be higher for an equivalent amount of natural gas consumed. This higher cost per unit of consumption would typically be considered a rate increase.

[62] As recently reported in the Wall Street Journal: "One in five U.S. households was behind on its utility bills coming out of last winter, a new survey concludes, raising fears that the current heating season could be even worse. One in 20 households had its utility service terminated in 2007." Rebecca Smith, *One in Five Households Fell Behind on Utility Bills Last Winter*, WALL STREET JOURNAL, December 17, 2008, at A6 (discussing a survey by the National Association of Regulatory Utility Commissioners).

Projected Savings from the Plan

VNG's customers who participate in the conservation measures proposed in the Plan can save money on the volumetric portion of their bills through reduced consumption. Quantifying total net savings for customers with accuracy is difficult, however. In this regard, we find VNG's claim that its customers, over a 10-year period, can save as much as $39.5 million from the Plan as proposed to be speculative.[63] While the *costs* to customers of the ECP will be definite, and price increases for non-gas service under the RNA Rider are probable, as explained above, attempting to quantify net *savings* from the Plan is an exercise dependent upon a myriad of changing factors, including the *future* behavior of customers and the *future* price of natural gas.

We note that on the date that VNG filed this Application (July 3, 2008), the price of natural gas at Henry Hub was $13.31 per MMBtu; by December 1, 2008, the price had plunged to $6.43,[64] a drop of *more than 50%* in just a few months. Whether prices will remain this low, go even lower, or skyrocket in the future is unknowable. In addition, while some of the recent drop in natural gas prices may be attributable to the worldwide decline in demand for all energy commodities because of the global economic crisis, there may also be reason to speculate that the natural gas markets in the United States are seeing the effects of substantial increases in domestic sources of supply, for example, from the Barnett field in Texas. There is also reportedly huge potential from the Marcellus Shale field in the Appalachian Basin.[65] The quantity of savings to customers on the volumetric portion of their bills from reduced consumption obviously moves in

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[63] *See* Exh. 2 (Gidley direct) at 6 ("For that level of expenditure [$7.5 million for the conservation programs, including the cost of capital], our customers can save up to $39.5 million over a 10-year period. *That is a permanent, sustainable savings that provides significant value to our customers*" (emphasis added).).

[64] *See, e.g.*, ICE Day Ahead Natural Gas Price Report published by ICE Data (https://www.theice.com/marketdata/reportcenter/reports.htm).

[65] This potential "super giant" gas field extends from far southwest Virginia through West Virginia, Ohio, Pennsylvania, and New York. *See, e.g.*, http://geology.com/articles/marcellus-shale.shtml.

concert with gas prices. There are, of course, other factors, such as finite pipeline capacity or the possibility of continued dollar devaluation in the future, that could put upward pressure on prices and increase savings from reduced consumption.

Accordingly, IT IS HEREBY ORDERED THAT:

(1) A three-year conservation ratemaking and efficiency plan, as permitted by § 56-600 *et seq.* of the Code of Virginia, is approved as set forth in this Order Approving Natural Gas Conservation and Ratemaking Efficiency Plan and shall become effective on January 1, 2009.

(2) The Revised Stipulation is approved as set forth herein.

(3) The ECP program costs shall be allocated as set forth herein.

(4) This matter is dismissed.

Commissioner Morrison participated in this matter.

Commissioner Dimitri did not participate in this matter.

AN ATTESTED COPY hereof shall be sent by the Clerk of the Commission to: Edward L. Flippen, Esquire, Kristian M. Dahl, Esquire, and Bernard L. McNamee, Esquire, McGuireWoods LLP, One James Center, 901 East Cary Street, Richmond, Virginia 23219-4030; C. Meade Browder, Jr., Senior Assistant Attorney General, Office of the Attorney General, Division of Consumer Counsel, 900 East Main Street, Second Floor, Richmond, Virginia 23219; and the Commission's Office of General Counsel and Divisions of Energy Regulation, Public Utility Accounting, and Economics and Finance.

ATTACHMENT E

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STATE CORPORATION COMMISSION

PRE-FILED STAFF TESTIMONY

APPLICATION

OF

VIRGINIA NATURAL GAS, INC.

CASE NO. PUE-2008-00060

September 25, 2008

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PART A

PREFILED TESTIMONY
OF
CODY D. WALKER

APPLICATION OF
VIRGINIA NATURAL GAS, INC.
CASE NO. PUE-2008-00060

Q1. PLEASE STATE YOUR NAME AND POSITION WITH THE COMMISSION.

A1. My name is Cody D. Walker. I am an Assistant Director in the Commission's Division of Energy Regulation.

Q2. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A2. My testimony will address the Virginia Natural Gas Company's ("VNG" or "Company") application requesting approval of a natural gas conservation and ratemaking efficiency plan ("efficiency plan") and associated decoupling mechanism. My testimony will:

- Provide an overview of the statutory provisions authorizing the development of efficiency plans and decoupling mechanisms;
- Discuss the various factors addressed by the Staff in its review of VNG's application;
- Summarize and discuss the merits of VNG's proposal; and,
- Finally, make alternative recommendations where appropriate.

STATUTORY BACKGROUND

Q3. PLEASE PROVIDE A SUMMARY OF THE STATUTORY PROVISIONS GOVERNING THE DEVELOPMENT OF EFFICIENCY PLANS AND ASSOCIATED RATE DECOUPLING MECHANISMS.

A3. VNG's application and the Commission's consideration of the application are governed by Chapter 25 (§ 56-600 et seq.) of Title 56 of the Code ("the Efficiency Act" or "the

Act"). The Efficiency Act consists of §§ 56-600, 56-601, and 56-602 of the Code of Virginia ("Code"). On advice of counsel, these statutes respectively set forth definitions; describe the objectives of efficiency plans; and, establish specific elements, conditions, and incentives for efficiency plans and decoupling proposals. Key definitions set forth in § 56-600 of the Code include:

> *"Allowed distribution revenue" means the average annual, weather-normalized, nongas commodity revenue per customer associated with the rates in effect as adopted in the applicable utility's last Commission-approved rate case or performance-based regulation plan, multiplied by the average number of customers served.*
>
> *"Cost-effective conservation and energy efficiency program" means a program approved by the Commission that is designed to decrease the average customer's annual, weather-normalized consumption or total gas bill, for gas and nongas elements combined, or avoid energy costs or consumption the customer may otherwise have incurred, and is determined by the Commission to be cost-effective after analyzing such program using the Total Resource Cost Test, the Societal Test, the Program Administrator Test, the Participant Test, the Rate Impact Measure Test, and any other test the Commission reasonably deems appropriate. The Commission may determine the weight to be given to a test. Without limitation, rate designs or rate mechanisms, customer education, customer incentives, and weatherization programs are examples of conservation and energy efficiency programs that the Commission may consider.*
>
> *"Decoupling mechanism" means a rate, tariff design or mechanism that decouples the recovery of a utility's allowed distribution revenue from the level of consumption of natural gas by its customers, including (i) a mechanism that adjusts actual nongas distribution revenues per customer to allowed distribution revenues per customer, such as a sales adjustment clause, (ii) rate design changes that substantially align the percentage of fixed charge revenue recovery with the percentage of the utility's fixed costs, such as straight fixed variable rates, provided such mechanism includes a substantial demand component based on a customer's peak usage, or (iii) a combination of clauses (i) and (ii) that substantially decreases the relative amount of nongas distribution revenue affected by changes in per customer consumption of gas.*
>
> *"Fixed costs" means any and all of the utility's nongas costs of service, together with an authorized return thereon, that are not associated with*

the cost of the natural gas commodity flowing through and measured by the customer's meter.

"Revenue-neutral" means a change in a rate, tariff design or mechanism as a component of a conservation and ratemaking efficiency plan that does not shift annualized allowed distribution revenue between customer classes, and does not increase or decrease the utility's average, weather-normalized nongas utility revenue per customer for any given rate class by more than 0.25 percent when compared to (i) the rate, tariff design or mechanism in effect at the time a conservation and ratemaking efficiency plan is filed pursuant to this chapter or (ii) the allocation of costs approved by the Commission in a rate case using the cost of service methodology set forth in § 56-235.2 or a performance-based regulation plan authorized by § 56-235.6, where a plan is filed in conjunction with such case.

Section 56-601 of the Code identifies the following objectives for alternative rate designs and other mechanisms, where feasible:

1. Provide utilities with better tools to work with customers to decrease the average customer's annual average weather-normalized consumption of natural gas;

2. Provide reasonable assurance of a utility's ability to recover costs of serving the public, including its cost-effective investments in conservation and energy efficiency as well as infrastructure needed to provide or maintain reliable service to the public;

3. Reward utilities for meeting or exceeding conservation and energy efficiency goals that may be established pursuant to the Virginia Energy Plan (§ 67-100 et seq.);

4. Provide customers with long-term, meaningful opportunities to more efficiently consume natural gas and mitigate their expenditures for the natural gas commodity, while ensuring that the rate design methodology used to set a utility's revenue recovery is not inconsistent with such conservation and energy efficiency goals;

5. Recognize the economic and environmental benefits of efficient use of natural gas; and

6. Preserve or enhance the utility bill savings that customers receive when they reduce their natural gas use.

Subdivision B of § 56-601 further authorizes natural gas utilities to implement alternative rate designs and other mechanisms that:

> *1. Replace existing utility rate designs or other mechanisms that promote inefficient use of natural gas with rate designs or other mechanisms that ensure a utility's recovery of its authorized revenues is independent of the amount of customers' natural gas consumption;*
>
> *2. Provide incentives for natural gas utilities to promote conservation and energy efficiency by granting recovery of the costs associated with cost-effective conservation and energy efficiency programs; and*
>
> *3. Reward utilities that meet or exceed conservation and energy efficiency goals on a weather-normalized, annualized average customer basis through the implementation of cost-effective conservation and energy efficiency programs.*

Section 56-602 of the Act contains a number of key provisions regarding the filing and consideration of efficiency plans and decoupling mechanisms. Among other things, these provisions:

- limit the applicability of decoupling clauses and efficiency plans to residential, small commercial and small general service customers;
- mandate that efficiency plans include: (i) a component to normalize the effects of weather in determining efficiency plan results, (ii) a decoupling mechanism, (iii) one or more energy efficiency programs, (iv) provisions addressing the needs of low-income or low usage residential customers, and (v) provisions to assure that the rates and service of non-participating customer classes are not impacted;
- permit phased or targeted implementation of rate or tariff design changes and efficiency programs;
- require the Commission to allow natural gas utilities to recover their incremental costs associated with cost effective efficiency plans;
- require participating utilities to file annual reports showing the year over year weather-normalized use of natural gas on an average customer basis, by customer class, as well as the incremental, independently verified net economic benefits created by the utility's cost-effective conservation and energy-efficiency programs during the previous year;

- require the Commission to grant a reasonable opportunity for participating utilities to earn performance based incentives of up to 15 percent of the independently verified net economic benefits resulting from their efficiency plans; and finally,

- preserve the Commission's authority under §§ 56-234.2, 56-235.2, or 56-235.6; but provides that the Commission may not reduce an authorized return on common equity or other measure of utility profit as a result of the implementation of a natural gas conservation and ratemaking efficiency plan.

Further Subdivision B of § 56-602 states, in part, "[t]*he Commission shall approve or deny, within 180 days, a natural gas utility's initial application for any revenue-neutral conservation and ratemaking efficiency plan that allocates annual per-customer fixed costs on an intra-class basis in reliance upon a revenue study or class cost of service study supporting the rates in effect at the time the plan is filed.*" [Emphasis added.]

As noted above, the Efficiency Act specifically preserves the bulk of Commission's authority under §§ 56-234.2, 56-235.2, or 56-235.6 of the Code. These statutes contain additional factors that must be considered by the Commission in evaluating VNG's application. Among other things, § 56-235.2B of the Code provides that:

> *Any rate, toll, charge or schedule of any public utility operating in this Commonwealth shall be considered to be just and reasonable only if: (1) the public utility has demonstrated that such rates, tolls, charges or schedules in the aggregate provide revenues not in excess of the aggregate actual costs incurred by the public utility in serving customers within the jurisdiction of the Commission, including such normalization for nonrecurring costs and annualized adjustments for future costs as the Commission finds reasonably can be predicted to occur during the rate year, and a fair return on the public utility's rate base used to serve those jurisdictional customers, which return shall be calculated in accordance*

with § 56-585.1 for utilities subject to such section; (1a) the investor-owned public electric utility has demonstrated that no part of such rates, tolls, charges or schedules includes costs for advertisement, except for advertisements either required by law or rule or regulation, or for advertisements which solely promote the public interest, conservation or more efficient use of energy; and (2) the public utility has demonstrated that such rates, tolls, charges or schedules contain reasonable classifications of customers. Notwithstanding § 56-234, the Commission may approve, either in the context of or apart from a rate proceeding after notice to all affected parties and hearing, special rates, contracts or incentives to individual customers or classes of customers where it finds such measures are in the public interest.

Section 56-235.2 further requires that the Commission "*shall, before approving special rates, contracts, incentives or other alternative regulatory plans under subsection A, ensure that such action (i) protects the public interest, (ii) will not unreasonably prejudice or disadvantage any customer or class of customers, ...*"

Section 56-235.6 of the Code governs performance based ratemaking plans and defines performance based ratemaking methodology as a "*method of establishing rates and charges that are in the public interest, and that departs in whole or in part from the cost-of-service methodology set forth in § 56-235.2.*" Subsection B of the statue provides that:

The Commission shall approve such performance-based ratemaking methodology if it finds that it: (i) preserves adequate service to all classes of customers (including transportation-only customers if for a gas utility); (ii) does not unreasonably prejudice or disadvantage any class of gas utility or electric utility customers; (iii) provides incentives for improved performance by the gas utility or electric utility in the conduct of its public duties; (iv) results in rates that are not excessive; and (v) is in the public interest. Performance-based forms of regulation may include, but not be limited to, fixed or capped base rates, the use of revenue indexing, price indexing, ranges of authorized return, gas cost indexing for gas utilities, and innovative utilization of utility-related assets and activities (such as a gas utility's off-system sales of excess gas supplies and release of upstream pipeline capacity, performance of billing services for other gas or electricity suppliers, and reduction or elimination of regulatory

requirements) in ways that benefit both the utility and its customers and may include a mechanism for automatic annual adjustments to revenues or prices to reflect changes in any index adopted for the implementation of such performance-based form of regulation. In making the findings required by this subsection, the Commission shall include, but not be limited to, in its considerations: (i) any proposed measures, including investments in infrastructure, that are reasonably estimated to preserve or improve system reliability, safety, supply diversity, and gas utility transportation options; and (ii) other customer benefits that are reasonably estimated to accrue from the gas or electric utility's proposal.

COMMISSION STAFF'S REVIEW

Q4. PLEASE DESCRIBE THE FACTORS CONSIDERED BY THE STAFF IN REVIEWING VNG'S EFFICIENCY AND RATEMAKING PLAN.

A4. In light of the various Statues governing VNG's proposed efficiency plan, the Staff's review gave significant weight to the following areas:

- the various cost/benefit tests conducted by VNG and the test results;
- the design of VNG's conservation and efficiency programs;
- whether the Company's proposed decoupling mechanism is revenue neutral as defined in Va. Code § 56-600;
- the extent to which VNG's proposals meet the objectives of Va. Code § 56-601 and the requirements Va. Code §§ 56-602 and 56-235.6;
- VNG's plans for evaluating the results of its efficiency plan and future reports to the Commission; and finally,
- possible alternative approaches to VNG's proposals.

VNG'S PROPOSAL

Q5. PLEASE PROVIDE A BRIEF SUMMARY OF THE COMPANY'S APPLICATION.

A5. VNG proposes to undertake a number of initiatives that are designed to encourage energy efficiency and increased conservation. These initiatives include the Community Outreach and Consumer Education Program, the Seasonal Checkup program, the Low-Income Weatherization program, the ENERGY STAR® Residential New Construction pilot program, and three other customer incentive programs designed to promote installation of higher efficiency furnaces and water heaters. The Company also proposes to implement a revenue decoupling adjustment, Rider D, in conjunction with these initiatives. Rider D would be applicable to the Company's residential rate schedules, Schedules 1 and 3. Rider D would consist of monthly rate adjustments and an annual true-up that are designed to produce average non-gas revenues per customer that are equal to the average non-gas revenue per customer produced by the rates and test year conditions established in Case No. PUE-2005-00057. The test year for that case was the 12 months ending March, 2005.

COST/BENEFIT TEST RESULTS

Q6. DID VNG CONDUCT ANY TESTS TO EXAMINE THE COST EFFECTIVENESS OF THE PROGRAMS?

A6. Yes. The Company examined various efficiency programs utilizing the Participant, Rate Impact Measure ("RIM"), Total Resource Cost ("TRC"), and Program Administrator ("PA") Tests. The application of these tests and their results are discussed in the Direct Testimony of Company witness Paul H. Raab. The Participant Test measures the impact of the program on those customers who are direct participants in a program i.e. the customers receiving the incentive or service. The RIM test measures the net impact on the Company's customers as a whole ignoring the participants' direct benefits. The TRC

test measures the overall impact on both participants and non-participants. The PA test estimates the impact on the Company in its administration of the program and avoidance of alternative resource costs.

The results of Mr. Raab's analysis are summarized in the following table:

Program	**Participant** Test B/C Ratio	**RIM** Test B/C Ratio	**TRC** Test B/C Ratio	**PA** Test B/C Ratio
Seasonal Check-Up	2.43	0.86	2.10	6.39
Low-Income Weatherization	3.07	0.67	2.07	2.07
Tank Water Heater	2.09	0.66	1.37	1.92
Tankless Water Heater	2.29	0.69	1.58	2.21
Space Heating	1.88	0.73	1.38	2.77
ENERGY STAR®	2.52	0.90	2.26	8.82
Summary of All Programs	2.32	0.66	1.32	1.92

A benefit to cost ("B/C") ratio greater than 1 indicates that a program's expected benefits are greater than the expected costs. Ratios less than 1 indicate that the programs expected costs exceed the expected benefits. As can be seen from these results, the various efficiency measures examined passed all tests with the exception of the RIM test. None of the programs pass the RIM test. This would indicate that VNG's customers that do not participate in any of the programs will be negatively impacted by the offering of the various programs. VNG's analysis indicates that approximately 3.9% of the customers will benefit from the proposed programs in a given year while 96.1% of the customers would be adversely impacted.

In considering these test results, it should be noted that the tests rely on a number of estimates that are likely to vary from actual experience. There are three particular areas of uncertainty that warrant specific mention and discussion. The first area is related

to the issue of free riders. A free rider is someone who would have undertaken the efficiency measure irrespective of the program offered by the utility but accepts the incentive payment for doing something that they would have done in the absence of the utility sponsored program. The seasonal efficiency check-up program can be used to provide a clear example of a free rider. The benefits of this program are largely produced by the replacement of furnace filters. Many people replace their furnace filters on a routine basis without a utility incentive. An example of a free rider would be such an individual who accepts the utility incentive for something that he would have done in any event. Mr. Raab assumed that there were no free riders in conducting the various cost benefit tests. The actual realized benefits and benefit to cost ratios that occur as a direct result of VNG's efficiency programs will be lower in this regard since there will likely be some participation by free riders.

The second uncertainty is associated with forecasted natural gas prices. The bulk of the expected benefits of the proposed programs are associated with reduced natural gas usage and associated lower natural gas costs. As such, the expected benefits are very sensitive to forecasted natural gas prices. Natural gas costs are notoriously difficult to predict. For example, the Henry Hub spot price declined from over $13 per MMBTU to around $8 per MMBTU from July 2008 to September 2008. As such, actual gas costs will likely vary from those used in Mr. Raab's measure of the cost effectiveness of the efficiency programs. Lower than predicted gas costs will produce lower than expected benefits while higher gas costs will produce higher than expected benefits.

The third uncertainty is related to the revenue implications and resulting rate impacts of VNG's proposals. The Company proposes to base the calculation of Rider D

on actual changes in the non-gas revenues of all Schedule 1 and 3 customers not just those participating in VNG's proposed efficiency programs. In conducting his cost effectiveness tests, Mr. Raab considered only the estimated impact that the various programs examined will have on VNG's non-gas revenues. As such, Mr. Raab's assessments do not reflect the full effects of VNG's proposed Rider D. While Mr. Raab's assessments may be appropriate in viewing the isolated impacts of individual programs, they do not reflect the full implications of VNG's proposed package of efficiency programs and decoupling mechanism. The actual revenue and rate implications of Rider D may in fact vary substantially from the aggregate impact reflected in Mr. Raab's summary of the cost effectiveness of all of the programs. VNG's decoupling mechanism essentially assumes that the only factor impacting the average weather normalized usage and non-gas revenue per customer is its offering of efficiency programs. Average weather normalized usage and non-gas revenue is in reality impacted by any number of factors. These factors include changing customer life styles, customer demographics, housing sizes, furnace and appliance efficiencies, customer price and inflation elasticities, customer awareness, and other factors that have nothing to do with VNG's offering of efficiency programs. Rider D would adjust for all of these ever changing conditions, not just those created by the Company's efficiency programs.

The impact of these changes from one time period to another can be quite dramatic. Attachment CDW-1 presents a table of the average weather normalized monthly usage per customer for the period 1995 through March, 2008. As can be seen from this table, average weather normalized usage per customer varies substantially over time during a period when the proposed efficiency programs were non-existent. Rider

D's actual impact on non-gas revenues and the associated rate implications will depend on how the current weather normalized usage and non-gas revenue per customer compare to the Rider D targets. If current average weather normalized usage of non-participating customers is lower than that reflected in Rider D, Rider D will place upward pressure on rates. If the average usage of non-participating customers is higher than the Rider D targets, Rider D will place downward pressure on rates. These rate and revenue implications will be explored more fully later in this testimony.

Q8. DID THE COMPANY EXAMINE THE COST EFFECTIVENESS OF THE COMMUNITY OUTREACH AND CUSTOMER EDUCATION PROGRAM?

A8. No, not directly. As noted by Mr. Raab, it is generally not possible to ascribe any energy savings to these types of programs. As such, the benefits of such programs cannot be quantified with any degree of certainty. Mr. Raab did however examine whether the benefits associated with the other efficiency programs would offset the administrative costs of the community outreach and customer education program and concluded that they would.

Q9. DO THE RESULTS OF THE COMPANY'S COST EFFECTIVENESS TESTS RAISE CONCERNS?

A9. Yes. Aside from the concerns associated with forecast uncertainties, VNG's cost-benefit tests also raise concerns with respect to the impacts on non-participating customers. As noted earlier, none of the efficiency programs examined by Mr. Raab pass the RIM test and approximately 96% of the Company's Schedules 1 and 3 customers will be adversely impacted by the Company's efficiency plan. The average annual impact of the costs incurred in providing the efficiency program on non-participating customers is expected

to be approximately $9 per customer. On the other hand, participating customers are expected to receive average annual benefits from the programs of approximately $150. It should be noted that these figures reflect only the impact of the program costs and resulting customer benefits. These figures do not reflect any of the revenue implications of Rider D. As discussed earlier, Rider D could place upward pressure on non-gas rates and that any such upward pressure could serve to decrease the benefits to participating customers and increase costs to non-participating customers. The disparate impact of VNG's efficiency plan on participating and non-participating customers and the potential for reduced energy efficiency savings to customers will be discussed in greater detail later in this testimony.

This obvious disparity between participating and non-participating customers is certainly of some concern. Whether this concern warrants Commission rejection or modification of VNG's proposals will depend on the weight ascribed to the RIM test and whether the programs are deemed to "*unreasonably prejudice or disadvantage any customer or class of customers*" contrary to §§ 56-235.2 and 56-235.6 of the Code. The weight to be ascribed to the RIM test and whether the efficiency plan unduly prejudices or disadvantages any customer or class of customer are matters of judgment that are solely within the Commission's discretion.

Q.10. IN THE EVENT THAT THE COMMISSION CONCLUDES THAT THE RIM TEST SHOULD BE GIVEN GREATER WEIGHT OR THAT THE PROPOSED PROGRAMS ARE UNDULY PREJUDICIAL, CAN THE PROGRAMS BE MODIFIED TO LESSEN THE DISPARITY BETWEEN PARTICIPATING AND NON-PARTICIPATING CUSTOMERS?

A.10. Yes, the Commission could require that the incentives paid through the various programs be reduced or that the scope of the programs be decreased. Such changes would of course decrease benefits to participants and possibly decrease overall benefits as measured by the TRC test.

Q11. DID THE COMPANY CONSIDER ALTERNATIVE PROGRAMS OR INCENTIVE PAYMENTS?

A11. Yes. The Company noted that it initially considered lower incentive payments for each of its planned rebate programs and subsequently revised those rebates upward based on actual equipment cost differentials. However, the Company did not study alternative funding levels for the low-income weatherization program. VNG did not perform detailed cost effectiveness tests on these lower rebate levels or on differing funding levels for the weatherization programs and notes that it believes that lower incentive levels would be insufficient to encourage participation. Additionally, the Company considered and rejected two other programs; a rebate program for customers converting from electric to gas, and a low cost weatherization kit. The Company did not perform detailed cost effectiveness test for either of these rejected programs.

The Commission may want to consider directing the Company to undertake further study of lower incentive payments if it determines that non-participating customers would be unduly impacted by VNG's efficiency plan.

REVENUE NEUTRALITY

Q12. IS THE COMPANY'S RIDER D "REVENUE NEUTRAL" AS DEFINED BY § 56-600?

A12. The Code defines revenue neutral as "*a change in a rate, tariff design or mechanism as a component of a conservation and ratemaking efficiency plan that ... does not increase or decrease the utility's average, weather-normalized nongas utility revenue per customer for any given rate class by more than 0.25 percent when compared to (i) the rate, tariff design or mechanism in effect at the time a conservation and ratemaking efficiency plan is filed pursuant to this chapter or (ii) the allocation of costs approved by the Commission in a rate case using the cost of service methodology set forth in § 56-235.2 or a performance-based regulation plan authorized by § 56-235.6, where a plan is filed in conjunction with such case.*"

Based on calendar years 2006 and 2007, Rider D would have increased the weather normalized non-gas revenues of the Company's Schedule 1 rate class for those time periods by 5.18 % and 6.39 % respectively had it been in effect. Rider D would have produced these revenue increases as a result of changing weather normalized customer usage that is not attributable to VNG's proposed efficiency programs. As explained earlier, Rider D would have the effect of increasing non-gas revenues during periods when average weather normalized usage and non-gas revenue per customer is lower than that reflected in the Rider D targets. That is precisely what would have happened in these recent time periods had Rider D been in effect. The Rider D targets are based on the twelve months ending March, 2005. Those targets represent a time period when average weather normalized usage and non-gas revenue were high when compared to more recent history. In fact, there has been no single consecutive 12 month period when actual usage conditions were higher than the Rider D targets since March, 2005. The revenue increases that would have been produced by Rider D and current customer

usage characteristics would have produced higher returns had Rider D been in effect. Staff witness Richard Taylor will discuss how the Company's return on equity would have been increased had Rider D been in effect.

Clearly, Rider D is not revenue neutral when compared to "*the rate, tariff design or mechanism in effect at the time a conservation and ratemaking efficiency plan is filed*" in that it increases average per customer non-gas revenues for Schedule 1 by more than .25 percent. The question then becomes is Rider D revenue neutral with respect to "*the allocation of costs approved by the Commission in a rate case using the cost of service methodology set forth in § 56-235.2 or a performance-based regulation plan authorized by § 56-235.6, where a plan is filed in conjunction with such case*?" The Company based the design of Rider D on the test year conditions examined in the Commission's acceptance of VNG's performance based regulation ("PBR") plan and seems to satisfy at least part of this definition of revenue neutral. The Staff is, however, uncertain as to what is meant by the phrase "*allocation of costs*" when used in this context. The Staff believes that Rider D preserves the "*allocation of costs*" on an inter-class basis but, as will be discussed more fully later in this testimony, not on an intra-class basis. As such, the Staff believes that there is some uncertainty as to whether the Company's decoupling mechanism is "*revenue neutral.*"

OBJECTIVES OF § 56-601

Q13. DOES THE COMPANY'S APPLICATION SATISFY THE OBJECTIVES OF § 56-601 OF THE CODE?

A13. As noted earlier, § 56-601 seeks to: provide utilities with better tools to work with customers to decrease the average customer's consumption of natural gas; provide

reasonable assurance that a utility recovers costs of serving the public, including its cost-effective investments in conservation and energy efficiency as well as infrastructure needed to provide or maintain reliable service to the public; reward utilities for meeting or exceeding conservation and energy efficiency goals; provide customers with meaningful opportunities to more efficiently consume natural gas and mitigate their expenditures for the natural gas commodity, while ensuring that the rate design methodology used to set a utility's revenue recovery is not inconsistent with such conservation and energy efficiency goals; recognize the economic and environmental benefits of efficient use of natural gas; and preserve or enhance the utility bill savings to customers when they reduce their natural gas use. The Staff believes that VNG's proposals meet or at least preserve opportunities to satisfy these objectives with one possible exception.

The Staff questions whether VNG's proposals meet the goal of preserving bill savings to customers who conserve. This question relates back to the Company's proposal to include all Schedule 1 and 3 customers in its calculation of the Rider D adjustments. As discussed earlier, Rider D will in effect adjust for all factors impacting the weather normalized use of gas by Schedule 1 and 3 customers not just those changes attributable to VNG's efficiency programs. One such factor is efficiency measures undertaken by customers without any assistance from VNG. Rider D would in effect eliminate customer savings associated with unassisted customer energy efficiency savings. Lost utility revenues associated with these customer efforts will be recovered through Rider D. As such, customers as a whole will not see the full benefits of customer

initiatives. Additionally, the savings to the customers undertaking the unassisted initiatives will be eroded to the extent that they are subject to the component of Rider D that is associated with unassisted efficiency measures.

The Staff tried to assess the potential for reduced savings by developing estimates of the annual savings available to an average Schedule 1 customer undertaking any of the various programs offered by the Company. These estimates were based on the 2007 billing rates including the weather normalization adjustment[1], the annual energy savings associated with various programs as estimated by Mr. Raab, and the Company's estimate of Rider D assuming that Rider D was in effect during 2007. In developing these estimates, the Staff allocated the reduced usage across the calendar months in proportion to how usage varied throughout the year for all of the programs with the exception of the space heating program. Usage reductions for this program were allocated in accordance with heating season usage. The following savings with and without the impact of Rider D for the various efficiency measures are as follows:

	Low Income Asst.	Water Heater	Tankless Water Heater	Space Heating	Energy Star
Base Billing	$ 904.45	$ 904.45	$ 904.45	$ 904.45	$ 904.45
Savings	$ 266.10	$ 58.34	$ 135.68	$ 81.92	$ 126.17
Rider D Charges	$ 9.08	$ 12.74	$ 11.38	$ 13.00	$ 11.55
Net Savings	$ 257.01	$ 45.59	$ 124.30	$ 68.92	$ 114.62
% Reduction	3.41%	21.84%	8.39%	15.87%	9.15%

[1] The Staff utilized the Company's WNA for billing cycle 21 since it best approximates the WNA that would have been applicable for the calendar month.

As can be seen from these estimates, Rider D would have reduced the savings realized by customers undertaking any of the above actions to improve their energy efficiency. The above percentages represent the impact of Rider D on non-participating customers who undertook the energy efficiency measure without utility assistance.

REQUIREMENTS OF § 56-602

Q14. DOES THE COMPANY'S APPLICATION SATISFY THE REQUIREMENTS OF § 56-602?

A14. Section 56-602 of the Code requires that VNG's efficiency plan include (i) a component to normalize the effects of weather in determining plan results, (ii) a decoupling mechanism, (iii) one or more energy efficiency programs, (iv) provisions addressing the needs of low-income or low usage residential customers, and (v) provisions to assure that the rates and service of non-participating customer classes are not impacted. The Staff believes that the Company's filing is in compliance with these requirements.

Section 56-602B further requires that VNG's efficiency plan must be revenue-neutral and allocate *"annual per-customer fixed costs on an intra-class basis in reliance upon a revenue study or class cost of service study supporting the rates in effect at the time the plan is filed."* The Staff is not sure what is meant by the phrase concerning the allocation of cost on an intra-class basis or what constitutes a revenue study or class cost of service study supporting the rates in effect at the time the plan is filed. "Intra" implies that this phrase is giving guidance with respect to the allocation of annual per customer fixed costs within the Schedule 1 and Schedule 3 classes. Consequently, the Staff considered whether the proposed efficiency plan would alter the allocation of annual per

customer fixed costs within Schedule 1 or 3 and concluded that VNG's efficiency plan would change the allocation between participating and non-participating customers within both classes. Additionally, the Company's design of Rider D seems largely predicated on its understanding of "allowed distribution revenue" as defined in § 56-600. As such, VNG designed Rider D to produce the same average per customer non-gas revenue that was produced by current rates assuming the twelve months ending March, 2005 test year conditions. The Staff is uncertain as to whether this constitutes "*a revenue study or class cost of service study supporting the rates in effect at the time the plan is filed.*"

Q15. CAN RIDER D BE STRUCTURED SUCH THAT IT REDUCES THE MAGNITUDE OF A POSSIBLE INCREASE IN THE AVERAGE WEATHER NORMALIZED PER CUSTOMER NON-GAS REVENUE OR CHANGES IN THE INTRA-CLASS ALLOCATION OF COSTS FOR SCHEDULES 1 AND 3?

A15. Yes, there are two alternative approaches that could reduce potential revenue increases or intra-class cost shifting. The first approach would be to limit Rider D such that it only reflects changes in consumption associated with customers directly receiving incentives or subsidies from VNG. This would assure that non-participating customers retain the full benefits of their self initiated efficiency efforts and that VNG not be rewarded for reductions in natural gas usage that are attributable to factors that are not within VNG's control. This could be accomplished by establishing historic base-lines for participating customers and then using those base-lines to estimate the usage reductions attributable to the Company's programs. The second approach would be to develop a more rigorous method for estimating what average weather normalized usage and non-gas revenue per

customer would have been in the absence of VNG's efficiency plan. The elasticity adjustment developed by Staff Witness Howard Spinner is an example of such an approach.

COMPLIANCE WITH §§ 56-235.2 AND 56-235.6 B

Q16. DOES THE COMPANY'S EFFICIENCY PLAN COMPLY WITH THE REQUIREMENTS OF § 56-235.6 B OF THE CODE?

A16. Virginia Code § 56-235.2 requires that the Commission "*shall, before approving special rates, contracts, incentives or other alternative regulatory plans under subsection A, ensure that such action (i) protects the public interest, (ii) will not unreasonably prejudice or disadvantage any customer or class of customers....*" Further § 56-235.6B states, in part, that "*The Commission shall approve such performance-based ratemaking methodology if it finds that it: (i) preserves adequate service to all classes of customers (including transportation-only customers if for a gas utility); (ii) does not unreasonably prejudice or disadvantage any class of gas utility or electric utility customers; (iii) provides incentives for improved performance by the gas utility or electric utility in the conduct of its public duties; (iv) results in rates that are not excessive; and (v) is in the public interest.*"

Whether the Company's plan meets these requirements is, once again, a matter of judgment that falls solely within the Commission's discretion. The Staff believes that there is particular concern with respect to whether the efficiency plan is prejudicial to certain customers and whether Rider D will result in rates that are not excessive. As noted earlier, VNG's efficiency plan will result in significant disparities and cost

reallocations between participating and non-participating customers. This shifting of costs could potentially be viewed as prejudicing or disadvantaging certain customer groups. Additionally, the Staff believes that increased revenue produced by Rider D under recent test year conditions raise a question as to whether VNG's proposals will result in rates that are not excessive. Based on an examination of the revenue and return on equity changes that would have occurred if Rider D had been in effect during 2006 or 2007, Rider D may have resulted in rates for those years that could be viewed as excessive. The Staff believes that the resulting increases in the Company's return on equity would have exceeded the Company's last authorized return on equity.

Q.17. IS VNG'S EFFICIENCY PLAN IN THE PUBLIC INTEREST?

A.17. A determination of whether the Company's plan is in the public interest requires a significant exercise of judgment and a careful balancing of sometimes conflicting objectives. Those judgments are reserved for the Commission's discretion and cannot be made by the Staff. The Staff can only offer information and analysis to assist the Commission in this regard. In that vein, the Staff believes that there are a number of outstanding questions which may impact the Commission's ultimate determination of whether the Company's efficiency plan is in the public interest. These questions include:

- Is the efficiency plan revenue neutral?
- Is the intra-class cost shifting that will take place as a result of the proposed plan permissible?
- Will certain customers be unduly disadvantaged by the proposed efficiency plan?

- Will savings resulting from efficiency improvements undertaken by customers be retained? and,
- Will Rider D result in excessive rates?

The Staff further notes that it is questionable whether VNG's proposals are fully in accord with the Governor's Energy Plan. That plan recommends, among a number of things, that "*Virginia should carefully implement a combination of natural gas local distribution utility revenue decoupling for energy-efficiency and conservation programs.*"[2] [Emphasis added] The Staff questions whether the proposed decoupling mechanism for Schedules 1 and 3 represents a careful implementation of decoupling since it captures changes that go far beyond those associated with the proposed efficiency programs.

EFFICIENCY PLAN REPORTING

Q18. VIRGINIA CODE § 56-602 E REQUIRES THE FILING OF ANNUAL REPORTS SHOWING THE YEAR OVER YEAR WEATHER-NORMALIZED USE OF NATURAL GAS ON AN AVERAGE CUSTOMER BASIS, BY CUSTOMER CLASS, AS WELL AS THE INCREMENTAL, INDEPENDENTLY VERIFIED NET ECONOMIC BENEFITS CREATED BY THE UTILITY'S COST-EFFECTIVE CONSERVATION AND ENERGY-EFFICIENCY PROGRAMS DURING THE PREVIOUS YEAR. HAS THE COMPANY DISCUSSED HOW IT WILL COMPLY WITH THIS REQUIREMENT?

[2] "The Virginia Energy Plan", 2007, page 10

A18. VNG did not address this reporting requirement in its application in this proceeding. The Company did, however, acknowledge its reporting obligations in response to a Staff interrogatory. That response also indicated that while VNG was not seeking a performance based incentive in this proceeding and had not developed measurement and verification protocols that it would develop a detailed proposal in such a filing. In response to a second interrogatory, the Company noted that it anticipated that it would conduct evaluation, measurement and verification of each efficiency program in accordance with industry accepted protocols such as the International Performance & Verification Protocol ("IPMVP"). VNG notes that "*The IPMVP applies common-sense techniques to the evaluation of programs and prescribes four options for performing the evaluation:*

> *Option A: Engineering calculations based on spot measurements*
> *Option B: Engineering calculations based on short-term monitoring*
> *Option C: Billing analysis at the whole-building level using statistical techniques*
> *Option D: Calibrated engineering simulation models"*

The Company has not specified a preferred option or options nor has it described the data that it intends to collect in the interim. Adequate data collection is essential since any after the fact evaluation is only as good as the available data. The IPMVP protocol focuses primarily on the usage changes attributable to energy efficiency programs and not on how those changes translate into economic benefits.

Q19. HOW WILL VNG ENSURE THE INDEPENDENT VERIFICATION OF THE NET ECONOMIC BENEFITS OF ITS EFFICIENCY PROGRAMS?

A19. That is unclear. Again in response to a Staff interrogatory, the Company noted that it had not decided whether to perform the evaluation in-house or to have the evaluation

performed by an outside expert. VNG further notes that independence is a moot issue if an outside expert is retained. Further, the Company apparently believes that in the event of an in-house evaluation that independence will be insured because all parties will have an opportunity to review the in-house evaluation and calculation of economic benefits.

Q20. DOES THE STAFF BELIEVE THAT THE COMPANY'S PLANS FOR REPORTING AND INDEPENDENTLY VERIFYING THE NET ECONOMIC BENEFITS OF ITS EFFICIENCY PLAN ARE ADEQUATE?

A20. No. The verification of the savings attributable to energy efficiency measures can be a complex and controversial matter particularly when such results are to be used as the basis for future utility incentives. Additionally, an after the fact evaluation is very dependent on data collection efforts and can only be as good as the available data. As such, the Staff believes that the Company's effort at developing a plan for measuring, verifying and determining the net economic benefits of its programs is inadequate at best. In fact, the Staff questions whether the Company has undertaken any such effort aside from responding to Staff interrogatories. Additionally, the Company seems reluctant to assume the obligation of assuring that its program results are independently verified and appears quite willing to place this burden on the Staff and other parties.

The Staff believes that the Company should be directed to engage an outside expert, develop detailed data collection plans with the outside expert's assistance, specify detailed measurement and verification protocols, specify the methodology for translating energy savings into net economic benefits and to file for approval of these measures prior to being allowed to implement its efficiency plan if such a plan is approved. This will enable comment by the Staff and other parties and allow the Commission to ensure an

accurate determination of the net economic benefits produced by the Company's energy efficiency programs.

Q21. DOES THE STAFF HAVE ANY ADDITIONAL COMMENTS REGARDING THE DESIGN OF RIDER D?

A21. Yes. The Staff has a number of concerns regarding the implementation of Rider D and the resulting complexity that will be involved in VNG's Schedule 1 and 3 customer billings. If approved, Rider D will involve a third adjustment to the bills of its residential customers. The Company currently adjusts bills to reflect changes in purchased gas costs and normal weather. The normal weather adjustment is performed on a real time basis. As such, that adjustment is quite complex and not readily understandable. Rider D represents a second very complex adjustment that involves a lag between the month being adjusted for and the actual application of the adjustment, rolling monthly corrections, an annual true-up, and a weather normalization methodology that differs from the real-time weather adjustment. The differing weather normalization methodology has the practical impact of undoing the real time weather adjustment and putting in place a differing weather adjustment. In short, Rider D renders the earlier weather adjustment meaningless with respect to the Company's overall revenues. The Staff is very concerned that this layering of rate adjustments can give rise to billing errors and increased customer confusion.

There are a number of possible approaches to decoupling that may be much simpler and more readily understood. The preferred approach depends to some degree on whether the decoupling mechanism is designed to recover only the lost revenues attributable to VNG's actual efficiency programs or to recover all changes impacting

customer usage. If the recovery of lost revenues is limited to participating customers, the magnitude of the dollars to be collected will be much smaller. Such amounts could simply be deferred for later collection much like the Company's plans for collecting the actual costs of its efficiency programs. In this event, Rider D could simply be implemented.

Should the Commission find that it is appropriate to approve a decoupling mechanism that adjusts for all the various factors impacting customer usage, the Commission could simply require that the Company's current real-time weather normalization for Schedules 1 and 3 be eliminated. This would eliminate one layer of billing complexity and ultimately collect the same level of revenue. Additionally, the Commission could direct a simpler rate design that collects the targeted level of non-gas revenue.

SUMMARY

Q22. PLEASE SUMMARIZE YOUR TESTIMONY.

A22. The Staff is concerned that the Company's proposed decoupling mechanism is unduly complicated and overly broad in that it adjusts for all possible changes impacting customer usage. This concern exacerbates the numerous questions that must be addressed in the Commission's determination of whether VNG's is in compliance with the various statutes and satisfies the overall public interest. As noted earlier these questions include:

- Is the efficiency plan revenue neutral?
- Is the intra-class cost shifting that will take place as a result of the proposed plan permissible?

- Will certain customers be unduly disadvantaged by the proposed efficiency plan?
- Will savings resulting from efficiency improvements undertaken by customers be retained? and,
- Will Rider D result in excessive rates?

Should the Commission find that these questions are of significant concern, it could consider limiting any decoupling adjustment to recovering those lost revenues directly attributable to the programs offered by VNG, decreasing the level of incentives provided to participating customers, developing a more rigorous method for estimating average weather normalized usage and non-gas revenue per customer as described by Staff Witness Spinner, directing the elimination of the Company's real time weather adjustment, and directing that the Company worked together with the Staff and other parties to this proceeding to develop a simpler rate design.

Additionally, the Staff believes that the Company's plans for collecting data and submitting reports to the Commission are inadequate. As such, the Staff recommends that the Company should be directed to engage an outside expert, develop detailed data collection plans with the outside expert's assistance, specify detailed measurement and verification protocols, specify the methodology for translating energy savings into net economic benefits and to file for approval of these measures prior to being allowed to implement its efficiency plan if such a plan is approved.

Q23. DOES THIS CONCLUDE YOUR TESTIMONY IN THIS PROCEEDING?

A23. Yes, it does.

Weather Normalized Usage
Per Customer

Average Weather Normalized CCF Usage per Customer

	Test Year	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Jan	14.71	15.28	14.64	14.54	14.73	15.49	15.54	13.99	14.39	14.44	15.98	14.71	14.04	13.19	13.32
Feb	11.88	12.10	11.67	11.73	12.16	10.21	12.04	10.74	11.30	12.97	12.21	11.88	10.64	10.93	10.74
Mar	7.74	9.38	8.43	8.44	8.85	9.38	8.72	8.69	8.52	8.43	8.92	7.74	7.70	8.00	8.12
Apr	5.25	4.87	4.56	3.67	4.13	4.18	4.47	4.15	4.84	4.97	5.25	3.94	4.05	3.65	
May	2.51	2.70	1.61	4.37	1.99	2.86	2.65	2.22	2.49	2.08	2.51	1.82	1.42	1.65	
Jun	1.31	1.46	1.70	0.97	1.47	1.06	1.35	1.20	1.35	1.48	1.31	1.23	1.25	1.23	
Jul	1.14	1.40	1.45	1.32	0.86	1.43	1.22	1.15	1.15	1.16	1.14	1.09	1.11	0.99	
Aug	1.17	1.45	1.17	1.20	1.36	1.21	1.00	1.61	1.06	1.11	1.17	1.02	0.95	1.13	
Sep	1.47	1.23	1.23	1.70	1.66	1.25	1.26	1.00	1.38	1.28	1.47	1.58	1.13	1.42	
Oct	2.57	3.24	3.25	3.27	3.22	2.90	3.21	2.85	3.18	3.14	2.57	3.54	2.69	3.31	
Nov	5.49	6.75	5.73	6.45	5.39	7.27	7.14	6.41	6.31	7.33	5.49	5.81	6.43	5.74	
Dec	11.75	11.84	11.99	12.17	10.93	12.47	11.87	10.86	11.81	12.11	11.75	10.95	10.86	11.25	
	66.98	71.71	67.44	69.85	66.74	69.71	70.48	64.86	67.78	70.51	69.76	65.30	62.28	62.49	

Variance From Test Year

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Jan	0.58	(0.07)	(0.17)	0.02	0.78	0.84	(0.72)	(0.31)	(0.27)	1.28	-	(0.66)	(1.51)	(1.39)
Feb	0.22	(0.22)	(0.16)	0.27	(1.68)	0.15	(1.15)	(0.59)	1.08	0.32	-	(1.24)	(0.96)	(1.15)
Mar	1.64	0.68	0.69	1.10	1.64	0.98	0.95	0.77	0.68	1.18	-	(0.04)	0.26	0.37
Apr	(0.38)	(0.69)	(1.58)	(1.12)	(1.07)	(0.77)	(1.10)	(0.41)	(0.28)	-	(1.31)	(1.20)	(1.60)	
May	0.19	(0.90)	1.86	(0.52)	0.34	0.14	(0.29)	(0.02)	(0.43)	-	(0.69)	(1.09)	(0.86)	
Jun	0.15	0.39	(0.34)	0.17	(0.25)	0.04	(0.10)	0.04	0.18	-	(0.08)	(0.06)	(0.08)	
Jul	0.26	0.32	0.19	(0.27)	0.30	0.08	0.02	0.01	0.03	-	(0.05)	(0.03)	(0.15)	
Aug	0.27	(0.00)	0.02	0.18	0.04	(0.17)	0.43	(0.12)	(0.06)	-	(0.15)	(0.23)	(0.05)	
Sep	(0.24)	(0.24)	0.23	0.19	(0.22)	(0.21)	(0.47)	(0.09)	(0.19)	-	0.11	(0.33)	(0.05)	
Oct	0.68	0.68	0.71	0.65	0.34	0.64	0.29	0.62	0.58	-	0.97	0.13	0.75	
Nov	1.26	0.25	0.97	(0.10)	1.78	1.65	0.92	0.82	1.84	-	0.32	0.95	0.25	
Dec	0.10	0.24	0.43	(0.82)	0.73	0.13	(0.89)	0.06	0.36	-	(0.80)	(0.88)	(0.49)	
	4.72	0.45	2.86	(0.24)	2.73	3.49	(2.13)	0.80	3.52	2.78	(1.68)	(4.70)	(4.50)	

PART B

PREFILED TESTIMONY

OF

RICHARD W. TAYLOR

VIRGINIA NATURAL GAS, INC.
CASE NO. PUE-2008-00060
SEPTEMBER 25, 2008

Q1. PLEASE STATE YOUR NAME AND POSITION YOU HOLD WITH THE STATE CORPORATION COMMISSION.

A1. My name is Richard W. Taylor, and I am a Manager of Audits for the Division of Public Utility Accounting.

Q2. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A2. I will discuss the impact that Virginia Natural Gas' ("VNG" or "the Company") proposed decoupling mechanism would have had if it had been in place during calendar years 2006 and 2007. I will also address the Company's proposal to defer the implementation costs related to its conservation and ratemaking efficiency plan.

Q3. PLEASE DISCUSS THE IMPACT OF THE DECOUPLING MECHANISM.

A3. Staff's Interrogatory No. 31 requested the Company to calculate the revenue impact that the decoupling mechanism ("Rider D" or "RNA") would have produced had it been in

effect in calendar years 2006 and 2007. The Company's response indicates that had the RNA been in effect during 2006 and 2007, it would have produced $4,094,691 and $5,079,081 in additional operating revenues, respectively. Staff compared the after-tax effect of these revenues with the level of common equity (jurisdictional) as reflected in the Company's AIF applications for the calendar years 2006 and 2007.

I have included Statements I and II for 2006 and 2007, respectively, that show the calculation of the basis point impact of Rider D for these years had it been in effect. As can be seen on Statements I and II, Rider D would have increased the return on equity by 150 basis points in 2006 and 184 basis points in 2007. These findings support Staff Witness Cody D. Walker's testimony that the RNA would have produced higher returns if Rider D had been in effect in 2006 and 2007.

Q4. PLEASE DISCUSS THE COMPANY'S PROPOSAL TO DEFER THE IMPLEMENTATION COSTS RELATED TO ITS CONSERVATION AND ENERGY EFFICIENCY PLAN.

A4. As noted in the testimony of Company Witness Hickerson, VNG proposes to defer the incremental costs required to implement its Energy Conservation Plan ("ECP"), including the cost of capital. The Company proposes to defer these costs pending cost of service treatment, including recovery in rates, until the expiration of the Company's Performance Based Regulatory Plan on July 31, 2011. The Company proposes to address the recovery of the deferred charges in a subsequent proceeding. The Company estimates that it will need to defer approximately $7.5 million in incremental charges.

Q5. DOES STAFF HAVE ANY CONCERNS REGARDING THE DEFERRAL OF THE INCREMENTAL COSTS?

A5. In its application for approval of a performance based rate regulation methodology pursuant to Virginia Code § 56-235.6 (Case No. PUE-2005-00057), the Company stated, "[i]f approved, the PBR Plan forces VNG to find ways to operate its business to gain efficiencies that offset that inflationary factor." In the same case, Company Witness Scott B. Carter stated in his Prefiled Testimony, "[a] PBR thus motivates a utility to focus on running the business (i.e., capacity solutions, cost management, economic development) rather than relying on rate increases."[1] In other words, VNG recognized the risk of inflation and rising costs and was willing to accept that risk during the five-year PBR period and attendant rate freeze. Now, however, in the current application, the Company appears to reverse the direction from the position on risk and cost increases that it maintained in its PBR application and testimony (Case No. PUE-2005-00057). By deferring the incremental charges for future recovery, the risk of cost increases will shift to VNG's ratepayers.

However, having said this, if the ECP is approved by the Commission, Virginia Code § 56-602 allows recovery of incremental costs. According to this statute,

[1] Application of Virginia Natural Gas, Inc., For Approval of a Performance Based Rate Regulation Methodology Pursuant to Virginia Code § 56-235.6, Case No. PUE-2005-00057, Prefiled Testimony of Scott B. Carter, page 5.

> "[t]he Commission shall allow any natural gas utility that implements a conservation and ratemaking efficiency plan under this chapter to recover, on a timely basis and through its regulated rates charged to its classes of customers participating in the plan, its entire incremental costs associated with cost-effective conservation and energy efficiency programs that are designed to encourage the reduction of annualized, weather-normalized natural gas consumption per customer."

Section 56-602 of the Code of Virginia further provides that ratemaking treatment may include the use of a deferral of incremental charges.

Since VNG is also seeking to defer the cost of capital related to the incremental ECP charges, the Commission will be required to determine the appropriate capital structure to use in the calculation of the cost of capital. Please refer to the testimony of Staff Witness Lawrence T. Oliver for the discussion of this issue.

Q7. DOES THIS COMPLETE YOUR TESTIMONY?

A7. Yes, it does.

Exhibit No._____
Witness: Taylor
Statement I

VIRGINIA NATURAL GAS, INC.
CASE NO. PUE-2008-00060
IMPACT OF RNA REVENUES
CALENDAR YEAR 2006

Rate Schedule 1 RNA Revenues	4,095,738
Rate Schedule 3 RNA Revenues	(1,047)
Total RNA Revenues	4,094,691
Less: Income Taxes @ 38.9%	1,592,835
RNA Revenues Net of Income Taxes	2,501,856
Common Equity Per Earnings Test (Jurisdictional)	166,689,893
Change in ROE Resulting from RNA	1.50%
Change in ROE Basis Points	150

Exhibit No._____
Witness: Taylor
Statement II

VIRGINIA NATURAL GAS, INC.
CASE NO. PUE-2008-00060
IMPACT OF RNA REVENUES
CALENDAR YEAR 2007

Rate Schedule 1 RNA Revenues	5,079,793
Rate Schedule 3 RNA Revenues	(712)
Total RNA Revenues	5,079,081
Less: Income Taxes @ 38.9%	1,975,763
RNA Revenues Net of Income Taxes	3,103,318
Common Equity Per Earnings Test (Jurisdictional)	168,440,923
Change in ROE Resulting from RNA	1.84%
Change in ROE Basis Points	184

PART C

PREFILED TESTIMONY
OF
HOWARD M. SPINNER

APPLICATION OF
VIRGINIA NATURAL GAS, INC.
CASE NO. PUE-2008-00060

Q1. PLEASE STATE YOUR NAME AND POSITION WITH THE COMMISSION.

A1. My name is Howard M. Spinner. I am Director of the Commission's Division of Economics and Finance.

Q2. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A2. My testimony will address the Virginia Natural Gas Company's ("VNG" or "Company") application requesting approval of a natural gas conservation and ratemaking efficiency plan ("efficiency plan") and associated decoupling mechanism. My testimony will:

- Provide general comments regarding the basic economic characteristics of decoupling mechanisms as they apply to regulated network utilities;
- Discuss possible interpretations of "cost effectiveness" as they apply to energy efficiency programs administered by regulated network utilities;
- Present the results of an econometric model that can be used to better insure that the Company appropriately benefits from the application of the decoupling mechanism should the Commission choose to adopt the decoupling mechanism proposed by the Company; and,
- Finally, make and support two specific recommendations in the event that the Commission approves the application generally consistent with VNG's filing. The recommendations are:

  (1) That any after-the-fact decoupling adjustment be based on usage data collected from the approximately 10,500 customers proposed for Company administered energy efficiency program participation, and

  (2) That any after-the-fact decoupling adjustment exclude direct natural gas price impacts derived from an elasticity estimate presented by Staff.

ECONOMIC CHARACTERISTICS OF DECOUPLING MECHANISMS

Q3. PLEASE PROVIDE AN OVERVIEW OF THE ECONOMIC CHARACTERISTICS OF THE TYPE OF DECOUPLING MECHANISM PROPOSED BY THE COMPANY IN THIS MATTER.

A3. The key definition set forth in § 56-600 that relates to "decoupling mechanisms" states as follows:

> *"Decoupling mechanism" means a rate, tariff design or mechanism that decouples the recovery of a utility's allowed distribution revenue from the level of consumption of natural gas by its customers, including (i) a mechanism that adjusts actual nongas distribution revenues per customer to allowed distribution revenues per customer, such as a sales adjustment clause, (ii) rate design changes that substantially align the percentage of fixed charge revenue recovery with the percentage of the utility's fixed costs, such as straight fixed variable rates, provided such mechanism includes a substantial demand component based on a customer's peak usage, or (iii) a combination of clauses (i) and (ii) that substantially decreases the relative amount of nongas distribution revenue affected by changes in per customer consumption of gas.*

The statute as set forth above includes two distinct meanings that create potentially complementary mechanisms to "decouple" utility net revenues and resulting utility financial performance from utility participation in the energy marketplace. In my view, the two defined mechanisms are very different and provide differing incentives to the utility. These differing incentives can be expected to impact the utility's performance as it attempts to carry out its public service obligations. These differing incentives may produce different results for VNG ratepayers.

According to the statute, one approach involves "*a mechanism that adjusts actual nongas distribution revenues per customer to allowed distribution revenues per customer, such as a sales adjustment clause.*" This is the choice that the Company has proposed for Commission approval in this application. VNG's proposal is based on an after-the-fact adjustment to utility customer charges to totally insulate the Company from a host of business conditions and factors --- some of them under the Company's direct control --- that ultimately result in the level of utility sales and, absent the relief requested here, the corresponding financial performance of the firm. According to VNG, the overarching objective of its proposal is to remove the utility's incentive to sell ever increasing amounts of natural gas. This incentive, currently in place, results from the collection of supposedly fixed, non-commodity delivery costs in a rate element that produces revenue that varies with gas usage.

In economic terms, the circumstance supposedly observed is that marginal revenues exceed marginal cost. This implies that Company financial performance will be enhanced by increased sales. Thus, all else held constant, the Company will have an incentive to increase sales. The problem with this incentive, so goes today's conventional wisdom, is that that the increased sale and consumption of natural gas raises natural gas prices and degrades the environment by contributing to global warming. On the other hand, it must be noted that making a firm financially indifferent to the level of its sales is a radical departure from the market system around which we have chosen to organize our economy. The adverse implications of this radical departure from our market system plus the advantages inherent in the second statutorily permitted definition of "decoupling mechanism," serve as the basis for this testimony.

Q4. BEFORE DESCRIBING THE SECOND MEANING FOR "DECOUPLING MECHANISM" SET FORTH IN THE STATUTE, PLEASE EXPLAIN WHY THE COMPANY'S PROPOSAL IS A RADICAL DEPARTURE FROM MARKET PRINCIPLES.

A4. It is hard to think of or imagine a firm that is indifferent to the level of its sales. Most always, a firm's financial performance depends on its sales level. So long as marginal revenues (prices) exceed costs, the more a firm sells the more it profits from its participation in our market economy. Importantly, key incentives may be lost if a firm becomes indifferent to its sales level. In short, the firm may no longer care about the many elements that promote customer and community satisfaction if all the firm has to do is "show up" and be paid.

Q5. EVEN IF THE COMPANY'S PROPOSAL IS A RADICAL DEPARTURE FROM MARKET PRINCIPLES, MIGHT SUCH A DEPARTURE BE WARRANTED TO SECURE THE ENVIRONMENTAL BENEFITS OF REDUCED NATURAL GAS CONSUMPTION?

A5. It is hard to determine the net local or global environmental impacts of changing levels of natural gas consumption. To the extent that natural gas does or does not displace some other source of energy, net environmental impacts must consider what, if anything, else is changing in the energy marketplace. It is even more difficult to determine the net societal impacts of changing levels of natural gas consumption. As an example, consider a heart surgeon driving to the hospital in her natural gas powered automobile to perform

an emergency surgery. If she is a quality surgeon, the faster she goes the more likely the patient will survive --- but increased speed increases the doctor's carbon footprint. How fast should she go?

Although decoupling mechanisms as proposed by VNG herein are currently very popular in the regulation of natural gas utilities, popularity is not necessarily correlated with sound policy. Removing utility incentives to increase natural gas sales levels substantially changes utility incentives and produces uncertain environmental benefits. It is impossible to determine the net effect of these actions.

Q6. PLEASE DESCRIBE THE SECOND MEANING OF A "DECOUPLING MECHANISM" SET FORTH IN THE STATUTE?

A6. The statute provides for a second definition of a "decoupling mechanism" as "*(ii) rate design changes that substantially align the percentage of fixed charge revenue recovery with the percentage of the utility's fixed costs, such as straight fixed variable rates, provided such mechanism includes a substantial demand component based on a customer's peak usage.*" Although the Company is not proposing to employ this alternative definition as the basis for the "decoupling mechanism" set forth in their application, this alternative definition deserves Commission consideration.

Staff's view is that VNG is concerned with operating in the face of two potentially conflicting business circumstances. First, and foremost in my view, is that the Company believes that substantial contributions to the Company's fixed delivery costs are collected by rates that produce revenues that vary with customer use. The Company believes that these rates significantly exceed marginal costs. This circumstance adds

unwanted risk to the Company's risk profile. To the extent that sales fall, the Company fears it will be unable to meet its financial objectives. In this proceeding, the Company's proposed decoupling mechanism is designed to protect its financial results against any decrease in use per customer, whatever the cause of the decrease.

The second circumstance faced by the Company relates to the first. VNG could fix its problem by increasing its fixed monthly customer charge and, at the same time, eliminate all non-gas delivery charges that vary with customer usage. That is, to the extent that fixed charges are no longer collected in rates that lead to revenue collection that vary with sales volumes, rates at the margin paid by customers will fall. And this fall in rates can be expected to stimulate sales volumes, all else held constant. And this increase in sales volumes is assumed to be bad for the environment and contrary to public policy.

While reducing the usage sensitive portion of customers' bills will tend to increase usage, all else held constant, it is not clear whether all non-gas delivery costs are appropriately collected in a fixed monthly customer charge. In reality, delivery costs do vary, over the long run, with customer usage --- especially usage during peak periods. VNG's monthly charge might not need increase by much --- and usage sensitive non-gas delivery charges fall by much --- such that customers receive an appropriate, cost-based price signal that equates usage sensitive non-gas delivery costs to long-run marginal delivery costs.

Q7. WHAT ARE THE MERITS AND DEMERITS OF ACHIEVING "DECOUPLING" VIA THE RATE-DESIGN BASED SECOND MEANING SET FORTH IN § 56-600?

A7. In general, my opinion is that a majority of regulatory economists, myself included, would prefer to employ rate design changes to provide appropriate incentives for the Company to supply and customers to consume the economically efficient level of gas sales. According to the Company, all non-gas delivery costs are fixed.[1] As such, collecting all fixed costs in a monthly customer charge would probably result in substantially higher customer charges. Staff feels that precipitous increases in the customer charge component of VNG's bill would cause substantial customer unhappiness. Therefore, Staff does not recommend a rate design change that increases customer charges such that all short-run fixed costs are collected in the customer charge. However, this does not mean that rate design changes can't be relied upon to produce proper incentives for the efficient use of natural gas.

Q8. DO YOU AGREE THAT ALL NON-GAS COMMODITY DELIVERY COSTS ARE FIXED?

A8. While non-gas commodity delivery costs are fixed in the short-run, in the long-run they are variable. The evidence supporting this notion is being installed under Hampton Roads right now. Over-time, increased sales volumes leads to increased levels of utility investment in delivery plant.

[1] *See* direct testimony of Company Witness Paul H. Raab, dated July 3, 2008, at page 12 of 24. He states: "Natural gas distribution utility costs do not vary with output and are not 'avoided' if volumes are reduced."

Another way to illustrate the idea that non-gas commodity delivery costs change as the level of gas carried on the system increases is as follows: ask the system planner how he would react over the next five years if he knew that delivered load would increase by 10%, 20%, 30% or more over the planning horizon. Presumably, differing levels of expected load would lead to different levels of incremental investment in the natural gas delivery system. Those differing levels suggest a long-run incremental cost of gas delivery for a natural gas utility that varies positively with system use.

Q9. WHAT IS THE IMPLICATION OF THE ABOVE DISCUSSION REGARDING SHORT-RUN AND LONG-RUN NATURAL GAS DELIVERY COSTS?

A9. VNG has proposed to decouple revenues from sales via an after-the-fact adjustment mechanism. The alternative is to employ a rate design that sets usage sensitive rate elements close to long-run marginal costs. If it is true that short-run marginal delivery costs are zero and that long-run marginal delivery costs are positive, at least two things follow: (1) VNG's current rate design collects a portion of its delivery costs in a usage sensitive charge and (2) it is not known how that rate element relates to long-run marginal delivery costs, (3) this collection via a usage sensitive delivery charge that exceeds short-run delivery costs (which are presumably zero) does indeed provide the Company with a mild incentive to sell more gas at the margin with all of the benefits and detriments of that incentive as discussed previously in this testimony.

Q10. HOW WOULD YOU RECOMMEND THE COMMISSION CONSIDER THE POLICY CHOICE THAT RESULTS FROM THIS MATTER?

A10. VNG's application and the Commission's consideration of the application are governed by the Natural Gas Conservation and Ratemaking Efficiency Act ("the Efficiency Act"). The Efficiency Act consists of §§ 56-600, 56-601, and 56-602 of the Code of Virginia. These statutes set forth definitions, describe the objectives of efficiency plans, and establish specific elements, conditions, and incentives for efficiency plans and decoupling proposals. Section 56-601 sets forth the following objectives, where feasible:

> *1. Provide utilities with better tools to work with customers to decrease the average customer's annual average weather-normalized consumption of natural gas;*
>
> *2. Provide reasonable assurance of a utility's ability to recover costs of serving the public, including its cost-effective investments in conservation and energy efficiency as well as infrastructure needed to provide or maintain reliable service to the public;*
>
> *3. Reward utilities for meeting or exceeding conservation and energy efficiency goals that may be established pursuant to the Virginia Energy Plan;*
>
> *4. Provide customers with long-term, meaningful opportunities to more efficiently consume natural gas and mitigate their expenditures for the natural gas commodity, while ensuring that the rate design methodology used to set a utility's revenue recovery is not inconsistent with such conservation and energy efficiency goals;*
>
> *5. Recognize the economic and environmental benefits of efficient use of natural gas; and*
>
> *6. Preserve or enhance the utility bill savings that customers receive when they reduce their natural gas use.*

Section 56-601 further authorizes natural gas utilities to implement alternative rate designs and other mechanisms that:

> *1. Replace existing utility rate designs or other mechanisms that promote inefficient use of natural gas with rate designs or other mechanisms that ensure a utility's recovery of its authorized revenues is independent of the amount of customers' natural gas consumption;*

2. Provide incentives for natural gas utilities to promote conservation and energy efficiency by granting recovery of the costs associated with cost-effective conservation and energy efficiency programs; and

3. Reward utilities that meet or exceed conservation and energy efficiency goals on a weather-normalized, annualized average customer basis through the implementation of cost-effective conservation and energy efficiency programs.

Finally, § 56-602, among other requirements, preserves the bulk of the Commission's authority under §§ 56-234.2, 56-235.2 or 56-235.6 to see that public utilities are regulated in a manner that promotes the public interest.

Speaking as a regulatory economist, the foregoing statutes governing VNG's proposed decoupling plan are easily made consistent with general, longstanding regulatory policies employed in Virginia and elsewhere that seek to ensure that regulated utility service advances the general public interest. In short, utility companies historically have been afforded by regulation an opportunity to earn an allowed cost-based return on invested capital sufficient to keep that capital in service to the public. At the same time, regulation strives to insure that rates are just and reasonable and that service is safe and reliable and provided by the utility without preference or discrimination.

It appears that the statutes adopted during the 2008 session of the Virginia General Assembly were inspired by environmental challenges that arose after the development of the longstanding regulatory principles set forth in the prior paragraph. In my view, our challenge is to simultaneously satisfy traditional regulatory objectives that remain in the law and today's new environmental challenges. Virginia's evolving public

utility regulatory statutes provide guidance in meeting those dual objectives. It also affords the Commission discretion in how those challenges are to be met.

Again, VNG has chosen to decouple by proposing to employ an administered after-the-fact true-up mechanism that substantially differs from the basic incentives and market principles that have long governed the American economy. An alternative approach would be to employ a rate design, also consistent with the statute, which sends the correct long-run price signal to customers regarding the true economic cost of consuming or not consuming an additional CCF of natural gas. It should be noted that, in an ideal world, the alternative energy choices available to VNG's customers should also be priced according to marginal cost principles. While non-regulated sources of supply (and conservation devices) are generally priced at the appropriate measure of marginal cost, the design of electric rates (being a substitute for natural gas) is an important consideration in this discussion. The design of electric rates, however, is beyond the scope of this proceeding.

Q11. MR. SPINNER, IF THE COMMISSION WERE TO DECOUPLE VIA RATE DESIGN AND THE USAGE SENSITIVE PORTION OF NATURAL GAS RATES DECREASED IN PRICE, WOULD NOT THAT TEND TO STIMULATE NATURAL GAS USAGE ABOVE CURRENT LEVELS?

A11. Yes, but only if the rate design employed lowered the usage sensitive charge associated with gas delivery below current levels. Absent a marginal cost study, we do not know

what the non-zero, long-run marginal cost of gas delivery is.[2] As such, we cannot determine what would happen to marginal prices faced by customers as a result of a rate design based approach to decoupling. The potential exists that such a rate design would still leave some diminished, yet healthy, level of business risk yet to be faced by VNG. But, that is the point. The Company should have an incentive to please consumers. Its profit level should not be 100% guaranteed by adjustment clauses. At the same time, consumers should receive an efficient price signal based on gas commodity costs plus long-run non-commodity delivery costs. Finally, even if a rate design based approach did lower prices at the margin and stimulate demand, it is possible --- although not guaranteed --- that well designed "efficiency" programs could efficiently reduce natural gas usage. I turn now to a discussion of the economics of efficiency programs.

COST-EFFECTIVE CONSERVATION AND ENERGY EFFICIENCY PROGRAMS

Q12. WHAT NEW STATUATORY PROVISIONS RELATE TO COST-EFFECTIVE CONSERVATION AND ENERGY EFFICIENCY PROGRAMS?

A12. Section 56-600 defines a cost-effective conservation and energy efficiency program as follows:

> *"Cost-effective conservation and energy efficiency program" means a program approved by the Commission that is designed to decrease the average customer's annual, weather-normalized consumption or total gas bill, for gas and nongas elements combined, or avoid energy costs or consumption the customer may otherwise have incurred, and is determined by the Commission to be cost-effective after analyzing such program using the Total Resource Cost Test, the Societal Test, the*

[2] Exhibit HMS-2 is a discovery response obtained from VNG. It states that "VNG has not prepared a marginal cost of service study to measure the marginal cost of gas delivery."

Program Administrator Test, the Participant Test, the Rate Impact Measure Test, and any other test the Commission reasonably deems appropriate. The Commission may determine the weight to be given to a test. Without limitation, rate designs or rate mechanisms, customer education, customer incentives, and weatherization programs are examples of conservation and energy efficiency programs that the Commission may consider.

The above definition confers discretion upon the Commission in the determination of cost-effectiveness as it applies to energy efficiency programs. In this matter, each conservation program proposed by the Company fails the rate impact measure ("RIM") test. This simply means that implementation of each of the programs will increase the Company's rates. Holding usage constant for non-participants in the programs means that the rate increase will directly result in utility bill increases for non-participants. Program participants may experience bill savings due to a program if the usage decline resulting from the program outweighs the rate increase caused by the program.

In Staff's view, failure to pass a RIM test casts doubt on the advisability of implementing the programs proposed by the Company. The programs as proposed will serve a limited number of VNG residential customers while all residential customers will be responsible for paying program costs.

In addition to all programs' failure to pass a RIM test, please note that changing certain key assumptions could change the results obtained from at least some of the other tests performed by Company witness Raab.

Q13. WHY IS PASSING A RIM TEST DEMONSTRATIVE OF PROGRAM COST EFFECTIVENESS?

A13. Before proceeding, I would like to clearly state that these views are my own, are shared by Staff, and are long held and carefully considered. However, efficiency-program cost effectiveness has been subject to vigorous debate for at least 25 years. The debate continues unabated --- and unsettled --- to this day.

Programs that pass a RIM test are almost certainly a good idea. Passing a RIM test means that at least some customers will experience bill savings while non-participants may also potentially benefit from program implementation via lower rates. The potential for programs to pass a RIM test is related to the utility's rate design. If a utility charges the same rate for service regardless of the time-varying cost of providing service, it is often the case that sales of some units during certain periods produce revenues that do not cover marginal cost. In such a circumstance, programs that reduce sales during periods when marginal costs exceed marginal revenues (rates) may reduce rates --- as long as the cost of the program do not exceed the savings attributable to the reduction of sales that do not cover costs. Another way of stating this point is that "peak-shaving" programs often pass a RIM test and often make good economic sense.

In this case, VNG has not offered programs specifically designed to shave peaking costs. In fact, Company Witness Raab states that "Natural gas distribution utility costs do not vary with output and are not 'avoided' if volumes are reduced."[3] In formulating the assumptions that underlie his analysis, he also states "it is assumed that the only costs avoided are the commodity costs....."[4] Given that (1) natural gas commodity costs are passed through to customers without markup, (2) there are positive

[3] *See* direct testimony of Company Witness Paul H. Raab, dated July 3, 2008, at page 12 of 24.
[4] *Id.*

contributions to fixed costs in usage based non-gas delivery charges in the short run, and (3) the Company's proposed programs cost something to deliver, the Company's programs simply cannot pass a RIM test unless they reduce usage during peak periods when rates do not cover costs.

To sum up, the Company states that its programs do not pass a RIM test and they are likely correct. Programs that do not pass a RIM test result in increased rates and, as such, are a concern to Staff.

Q14. PLEASE COMMENT ON WHAT WEIGHT SHOULD BE ATTRIBUTED TO THE COMPANY'S ASSERTION THAT ALL PROGRAMS PASS A TOTAL RESOURCE COST TEST?

A14. Company Witness Raab testifies that all of VNG's proposed efficiency programs under consideration in this matter pass a Total Resource Cost Test ("TRC"). Staff is concerned about the application of this test here because changing a few key assumptions could change the results of the test for some or all of the programs. Having said that, I note that Staff's main concern is the above stated failure of all programs to pass a RIM test. That being the case, I do not here undertake the task of redoing Mr. Raab's testing analysis using alternative assumptions to demonstrate that the programs fail the TRC test. Rather, I will conceptually discuss Company assumptions and how changing these assumptions could cause one or more of the Company's proposed programs to fail the TRC test. In my view, the value of the discussion is that it may sharpen thinking on energy efficiency cost-effectiveness testing in general.

Q15. PLEASE LAY OUT BASIC EFFICIENCY PROGRAM ECONOMICS.

A15. All energy efficiency program analysis begins with a consideration of program costs and benefits. The number one rule of cost/benefit analysis is that the analyst must consider all of the costs and benefits that stem from the analyzed program.

Program Costs

All utility administered energy efficiency programs begin with the expenditure of financial resources in the near term. These expenditures occur with relative certainty; the program is undertaken and the money is spent. In other words, a program begins with a relatively certain outlay of money "today" for capital (efficiency devices themselves or incentives to help consumers purchase those devices) and utility or contractor labor to install those devices. These costs are easily quantified and included in the analysis.

There are other costs that are much harder to quantify. Because of that difficulty, these real costs are almost always left out of efficiency program cost-benefit analysis. These costs are the costs that accrue to participant customers in installing and living with the efficiency measure. Throughout his testimony and spreadsheets provided in response to discovery, Company Witness Raab leaves placeholders for these costs but does not actually include any in his analysis. Again, due to the difficulty in cost quantification, this is standard practice in efficiency program cost-benefit evaluation. However, such an omission can lead to incorrect test results.

Program Benefits

In return for costs expended, energy efficiency programs are supposed to give rise to a cash flow over program or measure life. This cash flow equals the price of the energy

saved multiplied by the quantity of energy saved. This most basic type of energy efficiency program analysis is the TRC test.

Since quantities of saved energy are estimates and future energy prices are unknown, this benefit cash flow is relatively risky. Discounting this relatively uncertain cash flow back to today's present value allows for the comparison of program (or measure) benefits to program costs.

Note that the cash flow of program benefits is relatively uncertain for a number of reasons. Risks with the benefit cash flow include the actual energy savings of the program through time (i.e. How well will the insulation work over time?) as well as the future price of the energy that actually is saved. There is also a risk that the customer might change behavior in response to measure installation at that customer's location. For example, as a result of the program the customer might use more energy since the customer's effective cost of "energy services" (heat, hot water) has presumably been lowered by the energy efficiency program. This "bounce back" effect is often excluded from energy efficiency program analysis.

These risks to benefit cash flows, as well as other financial considerations, should inform the choice of the discount rate which is used to discount the benefit stream. The higher the discount rate applied to the expected benefit cash flow the lower the resulting present value benefit that must then be compared to the present value of the program's costs. Again, as for program costs, I have already stated my belief that total program costs are generally understated due to the systematic exclusion of hard to quantify customer costs.

Mr. Raab uses a relatively low discount rate set as the utility's cost of capital. The alternative use of a higher discount rate would reduce the present value of the benefit stream. That, plus the inclusion of hard to quantify customer costs, would lower the benefit/cost ratio of VNG's proposed programs possibly to the point where such programs do not pass the TRC test.

Q16. WHAT OTHER KEY ASSUMPTION HAS COMPANY WITNESS RAAB MADE THAT DRIVES HIS RESULTS AND IS OF CONCERN TO STAFF?

A16. Mr. Raab assumes that there are neither "free riders" nor "free drivers" associated with any of VNG's proposed programs. As he explains on page 13 and 14 of his direct testimony, his assumption is that the only customers who actually participate in the program do so because of the program and that no other customer installs program measures on their own. This is crucial to establish program cost effectiveness because it means that the program causes benefits to flow and that without the program no conservation takes place. The breadth and implication of this blanket assumption concerns Staff.

Q17. PLEASE USE ONE OF THE COMPANY'S PROPOSED PROGRAMS TO QUALITATIVELY DEMONSTRATE STAFF'S CONCERNS.

A17. Let us, for example, discuss the Company's proposed Seasonal Check-Up program. Careful consideration of program elements, characteristics and Company analysis illustrates the points made above.

First, note that according to the Company, the program cost is $76 and yields a gross, one-time, benefit (customer savings) of $160. The net saving per customer are posited as $160 - $76 = $84. Even with this $84 payoff, VNG analysis assumes that no customer will self-provide seasonal maintenance in the absence of the Company's program and that exactly 7,550 customers will procure seasonal maintenance if and only if they are paid an additional $25 incentive by VNG. This incentive payment raises the participant net benefit to $84 + $25 = $109 per participant.

The concerns of Staff stem from the application of the assumptions to the financial transaction of having one's heating system checked. The main query is this: Why won't customers undertake seasonal check-ups on their own without the incentive payment and reap an $84 net benefit? The potential answers to this question illustrate the problems with the Company's assumptions:

- There may be customer costs that actually accrue yet are not counted in the analysis. This might explain why customers do not have their systems checked-up on their own.
- Customers may have a different and possibly more accurate view of the benefits expected to result from the transaction as applied to their location. Customers may have some reason --- valid or not --- to believe that the seasonal check-up will not produce claimed benefits.
- Notwithstanding the assumptions made by VNG, if these cost and benefit numbers are approximately correct, some customers will have their systems serviced even if they are not included in the program.

These answers violate the Company's basic assumptions[5] and may indicate different outcomes in the Company's cost-effectiveness analysis. In sum, Staff is concerned that the Company's proposed programs may not actually pass a TRC that more accurately

[5] Again, those corresponding Company assumptions are (1) customer costs = 0, (2) use of a relatively low discount rate --- even for a program that lasts only one year, and (3) no free riders.

captures the benefits and costs of program implementation. Moreover, Staff is even more concerned that the Company's proposed programs do not pass a RIM test, a point that is not contested in this matter.

ECONOMETRIC RESULTS

Q18. WHAT IS THE PURPOSE OF THIS PORTION OF YOUR TESTIMONY?

A18. In the event that the Commission decides to adopt the Company's proposal regarding decoupling, Staff believes it is important that the Company's approved decoupling adjustment true-up of revenues per customer operates in a manner that reflects consumption changes due to the programs actually implemented by the Company. The Staff offers two suggestions to reach this goal.

Q19. WHAT IS STAFF'S FIRST SUGGESTION TO BETTER INSURE THAT ANY COMMISSION APPROVED DECOUPLING MECHANISM HOLDS THE COMPANY HARMLESS FOR CHANGES IN CUSTOMER CONSUMPTION THAT DIRECTLY RESULT FROM ENERGY EFFICIENCY PROGRAM IMPLEMENTATION?

A19. Staff suggests that, in the event that the Commission approves a method of decoupling that relies on an after-the-fact adjustment based on changes in customer gas consumption, the adjustment be derived only from the usage and revenue contribution history of the customers that actually participate in the six programs proposed by VNG in this matter. In other words, the Company would be protected by the decoupling mechanism from net revenue losses caused by energy efficiency programs for those customers actually

participating in a VNG administered efficiency programs. According to Schedule PHR-1, Statement 1 of Mr. Raab's direct testimony, about 10,500 of VNG's quarter million Schedule 1 customers are proposed for program participation. Participants are expected to number about 4.2% of VNG Schedule 1 customers.

Q20. WHAT IS STAFF'S SECOND SUGGESTION TO BETTER INSURE THAT ANY COMMISSION APPROVED DECOUPLING MECHANISM HOLD THE COMPANY HARMLESS FOR CHANGES IN CUSTOMER CONSUMPTION THAT DIRECTLY RESULT FROM ENERGY EFFICIENCY PROGRAM IMPLEMENTATION?

A20. Staff suggests that, in the event that the Commission approve a method of decoupling that relies on an after-the-fact adjustment based on changes in customer gas consumption, the adjustment be derived in a manner that insulates the Company from net delivery revenue lost as a result of program implementation rather than usage reduction caused by increases in the total cost of natural gas, including commodity natural gas costs.

As VNG Witness France states on page 5 of her pre-filed testimony in this matter "Especially during times of escalating fuel costs, the price of a commodity does provide an incentive to conserve." Ms. France then goes on to qualitatively posit that such incentives are fleeting.

I disagree that price impacts degrade over time, especially if high prices are sustained. That customers react to high prices with both short and long term strategies is generally accepted conventional wisdom. Increasing gasoline costs today impact today's and tomorrow's fuel consumption even if prices return to lower level. Short-term, we

cancel trips, form carpools, consolidate trips, take the bus, or choose a more fuel efficient vehicle from our fleet. Some of us might even slow down on the highway. Long-term, the stock of vehicles and they way they are operated change.

Natural gas consumption is no different. There are short-term and long-term reactions to price changes. Thermostats are changed, rooms are closed off or opened up, and heating sources are changed. Longer-term reactions include appliance stock change outs.

Q21. PLEASE DESCRIBE STAFF'S PROPOSED REMEDY FOR BETTER INSURING THAT ANY COMMISSION APPROVED DECOUPLING MECHANISM INCLUDE AN ADJUSTMENT FOR CONSUMPTION CHANGES CAUSED BY CHANGING TOTAL GAS COSTS.

A21. I have estimated a relatively simple econometric model that yields a short-run price elasticity estimate of demand for VNG's Schedule 1. I propose that this estimate be employed to adjust sales volumes in the latter period considered in the adjustment mechanism for changes in total natural gas prices that impact sales volumes beyond the impact reasonably attributable to the Company's energy efficiency programs.

The estimated price elasticity of demand is minus .135. This short-run estimate can be interpreted as the change in VNG Schedule 1 sales volumes that result from a given change in natural gas commodity costs. The estimated value implies that a 10% *increase* in natural gas commodity costs was associated with a 1.35% *decrease* in sales volumes over the 1993 to 2008 estimation period holding other factors constant.

Staff recommends that this price elasticity of demand adjustment factor be used to adjust current volumes down or up for commodity price increases or decreases, respectively, occurring between the between the base and current period used to determine appropriate charges to customers resulting from the adoption of an after-the - fact decoupling adjustment. Again, Staff also recommends that any such adjustment be based only on data from customers actually participating in a Company administered energy efficiency program.

The econometric model and data used in the estimation process are provided and fully documented in Exhibit HMS-1 attached to this pre-filed testimony.

Q22. PLEASE EXPLAIN HOW YOUR TESTIMONY RELATES TO THE REVENUE-NEUTRALITY ISSUE RAISED BY STAFF WITNESS CODY D. WALKER.

A22. Before providing the requested explanation, please note that the overall purpose of Staff's proposed elasticity adjustment is to better insure that the use of the after-the-fact adjustment decoupling mechanism as proposed by the Company works to insulate the Company from adverse financial impacts of Company administered energy efficiency programs. The Company believes that its programs will reduce non-gas distribution revenues per customer and seeks to avoid adverse financial impacts from such an outcome. Staff's elasticity adjustment is proposed to better target the Company's proposed Rider D charges to usage changes caused by the Company's energy efficiency programs as opposed to usage changes caused by increases or decreases in the total, per unit, delivered price of gas.

Staff Witness Walker testifies that Company proposed Rider D may not be consistent with the provisions of § 56-600 that define the meaning of "revenue-neutral." Staff's recommended elasticity adjustment, as well as Staff's recommendation that any Rider D adjustment be based on the usage of just those VNG customers actually participating in a Company administered energy efficiency program, would generally serve to temper the impact on utility average, weather-normalized nongas utility revenue per customer. That said, these recommendations are offered independently of the definitional issue raised by Mr. Walker. In other words, even in the absence of the revenue-neutrality issue, the two recommendations made in this testimony would still be offered to better insure that Rider D or any revision thereof work as it should.

Q23. PLEASE EXPLAIN HOW STAFF'S PROPOSED ELASTICITY ADJUSTMENT WOULD WORK IN PRACTICE CONJUNCTION WITH COMPANY PROPOSED RIDER D.

A23. Close inspection of Attachment ARH-1, pages 1 through 4 sponsored by Company Witness Hickerson reveals no explicit demonstration of how the supposedly reduced volumes resulting from the implementation of Company administered energy efficiency programs impact the calculation of Rider D. Using the terminology appearing in Attachment ARH-1, it appears that an elasticity adjustment[6] would change the volumes

[6] While details of the econometric model are included in an attachment to this testimony, important features of Staff's proposed elasticity adjustment are: (1) the econometric model is estimated for winter months (December through March), 1993 to 2008 for Schedule 1. Staff recommends that the elasticity factor apply to Schedule 1 and Schedule 3 for all months of the year. (2) In discovery, VNG provided Schedule 1 revenues net of customer charge revenues as well as Schedule 1 volumes. Schedule 1 revenues, net of customer charge revenues, divided by volumes is the "LMC" variable appearing in Staff's econometric model as an independent variable used to explain the variation in volumetric use per customer. More precisely, LMC is the natural log of the independent price variable in the model that represents the marginal cost of gas delivered to Schedule 1 customers. Staff's elasticity adjustment requires the calculation of this price variable in the base and current month ("the month to which the RNA factor will apply"). This yields a percentage price change that when multiplied by Staff's estimated elasticity coefficient, can be used to adjust gas volumes underlying the MBR calculation.

used to calculate Monthly Booked Revenues (MBR) which equals "non-gas revenue for the month as recorded on the Company's books for the Rate Schedule to which the Revenue Normalization Adjustment (RNA) applies excluding the RNA Factor."

The purpose of Staff's proposed elasticity adjustment is to adjust latter period volumes for changes in the delivered price of gas. Again, Staff believes that changes in customer use caused by VNG customer reaction to changes in the delivered price of gas should not impact the level of proposed Rider D. As such, Staff seeks to purge the Rider D calculation of that price change or elasticity impact. Should the Commission adopt Staff's elasticity adjustment mechanism, Staff recommends that the Company be directed to work with Staff to amend Rider D to reflect changes to applicable usage used to calculate the Revenue Normalization Adjustment Factor appearing in the Company's proposed Rider D tariff.

Q24. DOES THIS CONCLUDE YOUR PREFILED TESTIMONY IN THIS MATTER?

A24. Yes, it does.

EXHIBIT HMS_1

PREFILED TESTIMONY
OF
HOWARD M. SPINNER

APPLICATION OF
VIRGINIA NATURAL GAS, INC.
CASE NO. PUE-2008-00060

The purpose of this exhibit is to document the econometric model presented in the pre-filed testimony that accompanies this exhibit. The SAS code used to estimate the parameters is included in this exhibit as is the raw data as obtained from the Company in discovery. The SAS output containing model results are provided. Below, the variables are documented.

The purpose of the model is to estimate the relationship between the price paid for delivered natural gas by VNG Schedule 1 customers and the quantity of gas consumed by those customers. The model is estimated over a 15 year period using monthly "winter" data for December, January, February and March. The estimation period begins in December, 1993 and ends in March, 2008. There are 60 observations on the data set.

The dependant variable (LUCUS) is the natural log of usage per customer. The independent variables are the natural log of heating degree (LHDD) and the natural log of Schedule 1 total revenue minus customer charge revenue divided by number of customers. This variable is named LMC to indicate that the variable seeks to measure the marginal cost of delivered natural gas to VNG Schedule 1 customers. All data used in the model was obtained from VNG in discovery.

Model

LUCUS = f (LHDD, LMC)
As can be seen, the model is linear in logs. As such, the coefficients on LHDD and LMC can be interpreted as elasticities.

The coefficient on LHDD is 1.05767. This can be interpreted to indicate that a, say, 10% increase in HDD is correlated with a (10%*1.05767) 10.5767 % increase in UCUS, or usage per customer, holding all else constant.

The coefficient on LMC is (-0.13496). This can be interpreted to indicate that a, say, 10% increase in MC, the cost to the customer for natural gas delivered, is correlated with a (10%*0.13496) 1.3496 % decrease in UCUS, or usage per customer, holding all else constant.

```
EDIT      SCCHMS.PDS2.DATA(VNG1) - 01.18            Columns 00001 00072
****** ***************************** Top of Data ******************************
000001 //SCCHMSR JOB (SCC29INQUI,SPINNER,0010,015,0000),SPINNER,TIME=(,15),
000002 // CLASS=A,MSGCLASS=T
000003 // EXEC SAS
000004 //SYSOUT DD SYSOUT=T,HOLD=YES
000005 //DATA   DD DSN=SCCHMS.SAS.DATA,DISP=OLD
000006 //DATA1  DD DSN=SCCHMS.TRANS2.DATA,DISP=OLD
000007 //OUT1   DD DSN=SCCHMS.TRANSFER.DATA,DISP=OLD
000008 //*
000009 //SYSIN DD *
000010
000011 OPTIONS NODATE;
000012
000013 DATA TEMP1;
000014  INFILE DATA1;
000015    INPUT YEAR MONTH UCUSWN HDD NCUS MCF UCUS VTOTREV ADDS MC;
000016
000017 DATA TEMP1;
000018     SET TEMP1 ;
000019 IF HDD = 0 THEN HDD = 1; ELSE HDD = HDD;
000020
000021 DATA TEMP1; SET TEMP1;
000022 KEEP YEAR MONTH UCUS HDD MC;
000023
000024 DATA TEMP3; SET TEMP1;
000025
000026 LUCUS  =  LOG(UCUS);
000027 LMC    =  LOG(MC);
000028 LHDD   =  LOG(HDD);
000029
000030 PROC PRINT;
000031     VAR YEAR MONTH UCUS LUCUS MC LMC HDD LHDD;
000032
000033 DATA TEMP4;
000034     SET TEMP3;
000035 IF YEAR = 1991 OR YEAR = 1992 THEN DELETE;
000036 IF YEAR = 1993 AND MONTH LE 6 THEN DELETE;
000037
000038 DATA TEMP4;
000039     SET TEMP4;
000040 IF MONTH = 1 OR MONTH = 12 OR MONTH = 2 OR MONTH = 3;
000041
000042 PROC REG; MODEL LUCUS = LHDD LMC
000043
000044                / DW;
000045
```

THE REG PROCEDURE
MODEL: MODEL1
DEPENDENT VARIABLE: LUCUS

NUMBER OF OBSERVATIONS READ	60
NUMBER OF OBSERVATIONS USED	60

ANALYSIS OF VARIANCE

SOURCE	DF	SUM OF SQUARES	MEAN SQUARE	F VALUE	PR > F
MODEL	2	3.47808	1.73904	496.69	<.0001
ERROR	57	0.19957	0.00350		
CORRECTED TOTAL	59	3.67766			

ROOT MSE	0.05917	R-SQUARE	0.9457
DEPENDENT MEAN	2.36982	ADJ R-SQ	0.9438
COEFF VAR	2.49689		

PARAMETER ESTIMATES

VARIABLE	DF	PARAMETER ESTIMATE	STANDARD ERROR	T VALUE	PR > |T|
INTERCEPT	1	-4.05800	0.22943	-17.69	<.0001
LHDD	1	1.05767	0.03417	30.95	<.0001
LMC	1	-0.13496	0.02825	-4.78	<.0001

THE REG PROCEDURE
MODEL: MODEL1
DEPENDENT VARIABLE: LUCUS

DURBIN-WATSON D	1.693
NUMBER OF OBSERVATIONS	60
1ST ORDER AUTOCORRELATION	0.143

OBS	YEAR	MONTH	UCUS	LUCUS	MC	LMC	HDD	LHDD
1	1991	1	0.000	.	0.00	.	668	6.50429
2	1991	2	0.000	.	0.00	.	523	6.25958
3	1991	3	0.000	.	0.00	.	396	5.98141
4	1991	4	0.000	.	0.00	.	171	5.14166
5	1991	5	0.000	.	0.00	.	30	3.40120
6	1991	6	0.000	.	0.00	.	3	1.09861
7	1991	7	0.000	.	0.00	.	1	0.00000
8	1991	8	0.000	.	0.00	.	1	0.00000
9	1991	9	0.000	.	0.00	.	1	0.00000
10	1991	10	0.000	.	0.00	.	137	4.91998
11	1991	11	0.000	.	0.00	.	383	5.94803
12	1991	12	0.000	.	0.00	.	535	6.28227
13	1992	1	0.000	.	0.00	.	686	6.53088
14	1992	2	0.000	.	0.00	.	577	6.35784
15	1992	3	0.000	.	0.00	.	488	6.19032
16	1992	4	0.000	.	0.00	.	252	5.52943
17	1992	5	0.000	.	0.00	.	125	4.82831
18	1992	6	0.000	.	0.00	.	2	0.69315
19	1992	7	0.000	.	0.00	.	1	0.00000
20	1992	8	0.000	.	0.00	.	1	0.00000
21	1992	9	0.000	.	0.00	.	8	2.07944
22	1992	10	0.000	.	0.00	.	177	5.17615
23	1992	11	0.000	.	0.00	.	338	5.82305
24	1992	12	0.000	.	0.00	.	640	6.46147
25	1993	1	0.000	.	0.00	.	640	6.46147
26	1993	2	0.000	.	0.00	.	710	6.56526
27	1993	3	0.000	.	0.00	.	555	6.31897
28	1993	4	0.000	.	0.00	.	242	5.48894
29	1993	5	0.000	.	0.00	.	13	2.56495
30	1993	6	0.000	.	0.00	.	4	1.38629
31	1993	7	1.261	0.23191	6.74	1.90806	1	0.00000
32	1993	8	1.530	0.42527	5.95	1.78339	1	0.00000
33	1993	9	1.750	0.55962	6.13	1.81319	10	2.30259
34	1993	10	2.992	1.09594	6.53	1.87641	138	4.92725
35	1993	11	6.814	1.91898	6.87	1.92716	347	5.84932
36	1993	12	13.038	2.56787	7.05	1.95303	717	6.57508
37	1994	1	16.446	2.80008	7.00	1.94591	876	6.77537
38	1994	2	12.243	2.50495	6.93	1.93586	608	6.41017
39	1994	3	8.764	2.17065	6.67	1.89762	400	5.99146
40	1994	4	3.374	1.21610	6.07	1.80336	104	4.64439
41	1994	5	2.331	0.84630	6.05	1.80006	89	4.48864
42	1994	6	1.575	0.45426	5.39	1.68455	1	0.00000
43	1994	7	1.167	0.15444	4.77	1.56235	1	0.00000
44	1994	8	1.424	0.35347	5.07	1.62334	1	0.00000
45	1994	9	1.549	0.43761	6.20	1.82455	1	0.00000
46	1994	10	3.148	1.14677	6.70	1.90211	113	4.72739
47	1994	11	5.520	1.70838	6.90	1.93152	231	5.44242
48	1994	12	9.525	2.25392	7.13	1.96431	474	6.16121
49	1995	1	12.228	2.50373	7.01	1.94734	611	6.41510
50	1995	2	12.862	2.55428	6.77	1.91250	672	6.51026
51	1995	3	7.993	2.07857	6.38	1.85317	402	5.99645
52	1995	4	4.584	1.52257	5.83	1.76302	218	5.38450
53	1995	5	2.318	0.84070	5.68	1.73695	43	3.76120
54	1995	6	1.381	0.32281	5.08	1.62531	1	0.00000
55	1995	7	1.396	0.33361	5.91	1.77665	1	0.00000
56	1995	8	1.448	0.37018	6.41	1.85786	1	0.00000

OBS	YEAR	MONTH	UCUS	LUCUS	MC	LMC	HDD	LHDD
57	1995	9	1.177	0.16297	5.65	1.73166	4	1.38629
58	1995	10	1.877	0.62967	5.69	1.73871	78	4.35671
59	1995	11	9.239	2.22343	5.82	1.76130	491	6.19644
60	1995	12	14.179	2.65176	6.24	1.83098	761	6.63463
61	1996	1	16.196	2.78476	7.13	1.96431	854	6.74993
62	1996	2	13.112	2.57353	7.73	2.04511	708	6.56244
63	1996	3	11.198	2.41574	7.08	1.95727	621	6.43133
64	1996	4	4.713	1.55032	6.27	1.83578	241	5.48480
65	1996	5	2.295	0.83073	6.10	1.80829	99	4.59512
66	1996	6	1.760	0.56531	6.32	1.84372	7	1.94591
67	1996	7	1.452	0.37294	6.74	1.90806	1	0.00000
68	1996	8	1.174	0.16042	6.64	1.89311	1	0.00000
69	1996	9	1.098	0.09349	6.96	1.94018	1	0.00000
70	1996	10	2.756	1.01378	8.27	2.11263	124	4.82028
71	1996	11	9.513	2.25266	8.21	2.10535	559	6.32615
72	1996	12	10.526	2.35385	8.64	2.15640	561	6.32972
73	1997	1	13.702	2.61754	8.96	2.19277	728	6.59030
74	1997	2	9.809	2.28330	8.93	2.18942	531	6.27476
75	1997	3	7.450	2.00821	8.61	2.15292	423	6.04737
76	1997	4	5.211	1.65077	7.96	2.07443	314	5.74939
77	1997	5	4.885	1.58617	8.00	2.07944	90	4.49981
78	1997	6	1.734	0.55043	8.00	2.07944	44	3.78419
79	1997	7	1.324	0.28066	7.78	2.05156	1	0.00000
80	1997	8	1.197	0.17982	7.65	2.03471	1	0.00000
81	1997	9	1.587	0.46185	7.43	2.00553	1	0.00000
82	1997	10	3.235	1.17403	8.19	2.10291	148	4.99721
83	1997	11	7.859	2.06166	7.94	2.07191	434	6.07304
84	1997	12	12.631	2.53615	8.39	2.12704	662	6.49527
85	1998	1	10.949	2.39325	8.53	2.14359	573	6.35089
86	1998	2	9.498	2.25108	8.98	2.19500	492	6.19848
87	1998	3	8.676	2.16056	8.22	2.10657	466	6.14419
88	1998	4	3.714	1.31211	8.10	2.09186	211	5.35186
89	1998	5	1.935	0.66011	12.72	2.54318	60	4.09434
90	1998	6	1.399	0.33576	8.30	2.11626	1	0.00000
91	1998	7	0.865	-0.14503	7.18	1.97130	1	0.00000
92	1998	8	1.356	0.30454	8.01	2.08069	1	0.00000
93	1998	9	1.561	0.44533	7.39	2.00013	2	0.69315
94	1998	10	2.784	1.02389	7.87	2.06306	127	4.84419
95	1998	11	5.520	1.70838	7.87	2.06306	367	5.90536
96	1998	12	8.556	2.14663	8.11	2.09310	513	6.24028
97	1999	1	11.898	2.47637	8.12	2.09433	583	6.36819
98	1999	2	8.972	2.19411	8.13	2.09556	567	6.34036
99	1999	3	10.466	2.34813	8.04	2.08443	532	6.27664
100	1999	4	4.051	1.39896	7.81	2.05540	226	5.42053
101	1999	5	2.798	1.02890	7.91	2.06813	60	4.09434
102	1999	6	0.981	-0.01918	7.81	2.05540	1	0.00000
103	1999	7	1.431	0.35837	8.31	2.11746	1	0.00000
104	1999	8	1.213	0.19310	8.28	2.11384	1	0.00000
105	1999	9	1.191	0.17479	8.27	2.11263	4	1.38629
106	1999	10	2.789	1.02568	7.89	2.06560	144	4.96981
107	1999	11	5.790	1.75613	7.86	2.06179	282	5.64191
108	1999	12	11.525	2.44452	7.98	2.07694	588	6.37673
109	2000	1	15.354	2.73138	8.08	2.08939	762	6.63595
110	2000	2	10.859	2.38499	8.10	2.09186	570	6.34564
111	2000	3	6.745	1.90880	7.93	2.07065	371	5.91620
112	2000	4	4.360	1.47247	7.51	2.01624	227	5.42495

OBS	YEAR	MONTH	UCUS	LUCUS	MC	LMC	HDD	LHDD
113	2000	5	1.989	0.68763	7.52	2.01757	28	3.33220
114	2000	6	1.290	0.25464	9.26	2.22570	1	0.00000
115	2000	7	1.220	0.19885	9.94	2.29657	1	0.00000
116	2000	8	0.999	-0.00100	9.91	2.29354	1	0.00000
117	2000	9	1.376	0.31918	10.05	2.30757	13	2.56495
118	2000	10	2.885	1.05952	10.31	2.33311	133	4.89035
119	2000	11	9.153	2.21408	11.37	2.43098	466	6.14419
120	2000	12	15.404	2.73463	11.60	2.45101	824	6.71417
121	2001	1	14.386	2.66626	11.72	2.46130	793	6.67582
122	2001	2	9.808	2.28320	11.55	2.44669	583	6.36819
123	2001	3	9.108	2.20915	11.13	2.40964	497	6.20859
124	2001	4	4.264	1.45021	11.51	2.44322	239	5.47646
125	2001	5	2.007	0.69664	11.33	2.42745	52	3.95124
126	2001	6	1.129	0.12133	11.52	2.44408	1	0.00000
127	2001	7	1.153	0.14237	10.84	2.38324	1	0.00000
128	2001	8	1.606	0.47375	10.70	2.37024	1	0.00000
129	2001	9	1.230	0.20701	9.90	2.29253	19	2.94444
130	2001	10	3.098	1.13076	9.24	2.22354	163	5.09375
131	2001	11	4.791	1.56674	9.06	2.20387	275	5.61677
132	2001	12	7.627	2.03169	8.97	2.19389	468	6.14847
133	2002	1	11.679	2.45779	8.54	2.14476	629	6.44413
134	2002	2	9.493	2.25055	8.56	2.14710	537	6.28600
135	2002	3	7.053	1.95345	8.21	2.10535	398	5.98645
136	2002	4	3.399	1.22348	7.31	1.98924	157	5.05625
137	2002	5	2.720	1.00063	9.13	2.21157	75	4.31749
138	2002	6	1.334	0.28818	8.94	2.19054	3	1.09861
139	2002	7	1.149	0.13889	9.54	2.25549	1	0.00000
140	2002	8	1.057	0.05543	9.56	2.25759	1	0.00000
141	2002	9	1.250	0.22314	9.88	2.29051	1	0.00000
142	2002	10	2.519	0.92386	9.87	2.28950	115	4.74493
143	2002	11	7.427	2.00512	9.64	2.26592	419	6.03787
144	2002	12	12.928	2.55940	9.49	2.25024	697	6.54679
145	2003	1	16.565	2.80729	10.65	2.36556	884	6.78446
146	2003	2	13.596	2.60978	10.77	2.37676	665	6.49979
147	2003	3	7.248	1.98073	12.74	2.54475	413	6.02345
148	2003	4	4.928	1.59493	11.19	2.41502	231	5.44242
149	2003	5	2.233	0.80335	9.22	2.22138	71	4.26268
150	2003	6	1.447	0.36949	11.03	2.40062	2	0.69315
151	2003	7	1.163	0.15100	12.45	2.52172	1	0.00000
152	2003	8	1.113	0.10706	13.43	2.59749	1	0.00000
153	2003	9	1.243	0.21753	13.77	2.62249	5	1.60944
154	2003	10	2.575	0.94585	13.30	2.58776	120	4.78749
155	2003	11	5.032	1.61582	13.42	2.59675	239	5.47646
156	2003	12	12.034	2.48774	12.22	2.50307	634	6.45205
157	2004	1	16.781	2.82025	11.49	2.44148	814	6.70196
158	2004	2	12.416	2.51899	11.53	2.44495	643	6.46614
159	2004	3	7.424	2.00472	12.14	2.49651	396	5.98141
160	2004	4	4.585	1.52279	11.75	2.46385	198	5.28827
161	2004	5	1.789	0.58166	11.06	2.40333	25	3.21888
162	2004	6	1.233	0.20945	12.58	2.53211	1	0.00000
163	2004	7	1.136	0.12751	12.35	2.51366	1	0.00000
164	2004	8	1.174	0.16042	12.30	2.50960	1	0.00000
165	2004	9	1.375	0.31845	12.02	2.48657	2	0.69315
166	2004	10	2.661	0.97870	12.49	2.52493	155	5.04343
167	2004	11	5.355	1.67803	12.28	2.50797	353	5.86647
168	2004	12	11.557	2.44729	12.41	2.51850	628	6.44254

OBS	YEAR	MONTH	UCUS	LUCUS	MC	LMC	HDD	LHDD
169	2005	1	13.701	2.61747	12.34	2.51285	719	6.57786
170	2005	2	12.302	2.50976	11.70	2.45959	654	6.48311
171	2005	3	10.155	2.31797	10.96	2.39425	602	6.40026
172	2005	4	4.091	1.40879	11.83	2.47064	241	5.48480
173	2005	5	2.659	0.97795	12.03	2.48740	107	4.67283
174	2005	6	1.267	0.23665	12.42	2.51931	6	1.79176
175	2005	7	1.088	0.08434	11.93	2.47906	1	0.00000
176	2005	8	1.021	0.02078	16.69	2.81481	1	0.00000
177	2005	9	1.446	0.36880	17.73	2.87526	1	0.00000
178	2005	10	2.776	1.02101	18.22	2.90252	110	4.70048
179	2005	11	5.012	1.61184	18.42	2.91344	318	5.76205
180	2005	12	12.217	2.50283	16.34	2.79362	705	6.55820
181	2006	1	9.602	2.26197	15.84	2.76254	538	6.28786
182	2006	2	10.414	2.34315	14.60	2.68102	620	6.42972
183	2006	3	7.871	2.06319	14.04	2.64191	484	6.18208
184	2006	4	2.815	1.03496	13.98	2.63763	168	5.12396
185	2006	5	1.283	0.24920	10.94	2.39243	56	4.02535
186	2006	6	1.170	0.15700	12.38	2.51608	1	0.00000
187	2006	7	1.110	0.10436	13.73	2.61958	1	0.00000
188	2006	8	0.948	-0.05340	13.74	2.62031	1	0.00000
189	2006	9	1.211	0.19145	13.58	2.60860	11	2.39790
190	2006	10	2.960	1.08519	12.39	2.51689	164	5.09987
191	2006	11	5.447	1.69506	14.68	2.68649	308	5.73010
192	2006	12	8.642	2.15663	13.92	2.63333	521	6.25575
193	2007	1	9.549	2.25644	14.36	2.66445	580	6.36303
194	2007	2	13.129	2.57482	12.66	2.53845	748	6.61740
195	2007	3	7.260	1.98238	13.67	2.61520	436	6.07764
196	2007	4	4.181	1.43055	11.98	2.48324	261	5.56452
197	2007	5	2.067	0.72610	12.59	2.53290	85	4.44265
198	2007	6	1.193	0.17647	12.95	2.56110	2	0.69315
199	2007	7	0.990	-0.01005	14.35	2.66375	1	0.00000
200	2007	8	1.127	0.11956	14.14	2.64901	1	0.00000
201	2007	9	1.283	0.24920	14.86	2.69867	1	0.00000
202	2007	10	1.566	0.44852	15.00	2.70805	58	4.06044
203	2007	11	6.140	1.81482	14.13	2.64830	381	5.94280
204	2007	12	9.127	2.21124	14.34	2.66305	526	6.26530
205	2008	1	11.988	2.48391	13.60	2.61007	702	6.55393
206	2008	2	8.764	2.17065	14.87	2.69935	528	6.26910
207	2008	3	6.141	1.81499	16.16	2.78254	371	5.91620
208	2008	4	3.538	1.26356	16.43	2.79911	206	5.32788
209	2008	5	1.804	0.59001	17.39	2.85590	73	4.29046
210	2008	6	1.133	0.12487	18.89	2.93863	1	0.00000

Virginia Natural Gas, Inc.
Case No. PUE-2008-00060
The Staff of the State Corporation Commission
Fourth Set of Data Requests
August 15, 2008

Question 33:

Please provide any marginal cost of service study performed by the Company that seeks to measure marginal cost of gas delivery.

Response:

VNG has not prepared a marginal cost of service study to measure the marginal cost of gas delivery.

This response was prepared by or under the supervision of Archie Hickerson.

Jodi Gidley is the Company Officer responsible for the subject matter addressed herein.

PART D

PRE-FILED TESTIMONY
OF
LAWRENCE T. OLIVER

VIRGINIA NATURAL GAS, INC.

CASE NO. PUE-2008-00060

Q1. PLEASE STATE YOUR NAME AND POSITION WITH THE COMMISSION.

A1. My name is Lawrence T. Oliver. I am an Assistant Director in the Commission's Division of Economics and Finance.

Q2. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A2. As Staff Witness Richard W. Taylor has testified, the Company is proposing to defer the implementation costs associated with its proposed natural gas conservation and ratemaking efficiency plan ("efficiency plan") and associated decoupling mechanism. It is my understanding from Mr. Taylor that the Company is proposing to include a return component in its deferral based on the return authorized in its 1996 general rate case. My testimony provides the Commission with some evidence on what may be an appropriate return should the Company decide to book a return on these costs.

Q3. WHAT IS THE COMPANY'S POSITION WITH REGARD TO THE RATE AT WHICH IT WILL ACCRUE A RETURN ON ITS PROPOSED DEFERAL?

A3. It is my understanding that the Company intends to accrue a return based on the cost of capital VNG had in effect when it was acquired by AGL Resources Inc. ("AGLR") in 2000. This return is based on the consolidated capital structure of VNG's former parent company, Consolidated Natural Gas Company. ("CNG"), and a cost of equity that was

established based on market conditions at the time in Case No. PUE-1996-00277. In Case No. PUE-2001-00307, VNG's first AIF after being acquired by AGLR, the Staff Report, dated October 31, 2002, endorsed the Company's proposal to use a hypothetical CNG capital structure that maintained an overall return of 8.91% with a 10.90% cost of equity for AIF purposes until the issues of return on equity and capital structure could be addressed together in a rate proceeding. This agreement was accepted by the Commission's Order Accepting Agreement And Dismissing Proceeding, dated April 2, 2003, in Case No. PUE-2001-00307.

Q4. DO YOU SEE ANY PROBLEMS WITH THE COMPANY'S INTENTION OF USING THIS HYPOTHETICAL RATE AT WHICH TO ACCRUE CAPITAL COSTS?

A4. Yes. Beside the fact that this 8.91% cost of capital is based on CNG's capital structure, a company that has not accessed capital for VNG for at least 8 years, the Commission has found more current capital costs to be just and reasonable for VNG. Most recently in a general rate proceeding involving VNG, docketed as Case No. PUE-2005-00062, the Commission rejected the Company's proposal to use a hypothetical proxy-group capital structure and a return on equity of 11.0%. Instead, the Commission adopted the Hearing Examiner's recommendation in that case to use the actual consolidated AGLR capital structure proposed by Staff and a 10.0% return on equity within a range of 9.5% to 10.5%, in its determination of just and reasonable rates under § 56-235.2 A of the Code.

Q5. ARE THERE ANY STATUTORY PROVISIONS THAT MAY PROVIDE THE COMMISSION WITH SOME GUIDANCE AS TO WHAT RATE THE COMPANY SHOULD BE ALLOWED?

A5. The Company filed its efficiency plan under Chapter 25 of Title 56 of the Code of Virginia. Unlike Section § 56-235.9, recovery of funds used for capital projects prior to a rate case for strategic natural gas facilities, which specifies that the return embedded in current rates shall be used for purposes of accruing AFUDC, Chapter 25 of Title 56 does not specify the cost of capital to be used.

Q6. DOES THIS CONCLUDE YOUR TESTIMONY?

A6. Yes.

ATTACHMENT F

Exhibit 4

REVENUE DECOUPLING FOR GAS UTILITIES: KNOW YOUR OBJECTIVES

Ken Costello
Senior Institute Economist
The National Regulatory Research Institute

MACRUC 11th Annual Convention

Williamsburg, Virginia

June 5, 2007

Background and Context

- Lot of activity on the natural gas side for revenue decoupling (RD) and other revenue stabilization mechanisms
- Beginning to see renewed interest in the electricity sector
- Increased emphasis on energy efficiency by policymakers (e.g., National Action Plan for Energy Efficiency)
- Revenue stabilization has become important for gas utilities

Background and Context -- *continued*

- Conservation advocates see RD as essential for utility-initiated conservation activities
- Several RD proposals for gas utilities approved in the past year
- Rejections of RD by some state commissions
- Gas utilities have proposed revenue stabilization mechanisms other than RD (e.g., SFV rate design, earnings sharing, higher customer charges)

Background and Context -- *continued*

- Debate still focused on policy and fundamental issues on the merits of RD as a ratemaking mechanism advancing specified regulatory and policy objectives
- Implementation issues have gotten increased attention – "the devil is in the details" (e.g., rate collar, demand factors considered in rate adjustment, cost-of-capital effect, accounting for overall utility earnings)

Arguments for Revenue Decoupling

- No other ratemaking method achieves the dual objectives of revenue stability and stimulation of energy efficiency
- Without RD, a utility would not have a reasonable opportunity to earn its authorized rate of return
- Prevailing implementation of two-part tariff is flawed in recovering most of a utility's fixed costs in the volumetric charge

Arguments for Revenue Decoupling

-- continued

- How can regulators expect a utility to promote energy efficiency when it would be contrary to shareholders' interest?
- RD satisfies the customary 3-part regulatory test for the approval of trackers
- RD would reduce the frequency of future rate cases

Arguments for Revenue Decoupling

-- continued

- RD would assist in stabilizing winter gas bills
- Evidence so far point to generally favorable outcomes from RD for gas utilities
- RD does not affect rate design and would have only an incremental effect on rates
- RD preferred to SFV rate design and other approaches for producing revenue stability

Arguments against Revenue Decoupling

- Even with declining average gas usage, a utility can earn its authorized rate of return between rate cases by adding new customers and improving its productivity
- RD makes a utility less aggressive in controlling its costs
- RD is not needed to get a utility seriously involved in promoting energy efficiency
- No convincing rationale for utility involvement in promoting energy efficiency

Arguments against Revenue Decoupling -- *continued*

- Declining average gas usage has not substantially affect a utility's past earnings
- Question of whether declining average gas usage will continue in the future
- Adjusting rates for other than conservation improvements is unreasonable and imposes excessive risk on customers

Arguments against Revenue Decoupling -- *continued*

- Reducing future rate cases could cause a utility to over-earn in the future from a mismatch of revenues with costs
- Alternatives to RD are superior for addressing the downward trend of gas usage per customer
- Revenue stabilization is not a legitimate ratemaking objective

Arguments against Revenue Decoupling -- *continued*

- Instead of just focusing on revenues and declining average gas usage – which represents a form of "piecemeal regulation" – state commissions should place their emphasis on the overall profitability of a utility
- RD shifts business risk to consumers without any apparent benefits to them
- From an pure economics perspective, SFV is preferred to RD

The Challenge for Regulators: What's in the Public Interest?

- Cogent arguments, in support of advancing specific regulatory objectives, presented before state commissions on both sides of the RD debate
- Some of the arguments, however, are feeble (or even foolish), and state commissions should immediately weed them out
- Regulators should articulate their ratemaking objectives and the relative importance of each one (i.e., place weights on the different objectives, which requires judgment by regulators)

The Challenge for Regulators --
continued

- The tough task for regulators is to reconcile the conflicting objectives of ratemaking (e.g., revenue stability and minimal shifting of business risk to customers)
- Ratemaking has always entailed the compromise of different regulatory objectives
- Regulators need to understand the tradeoffs involved – no single ratemaking mechanism most effectively satisfies all regulatory objectives

The Challenge for Regulators --
continued

- Regulators should look at an individual utility's circumstances to assess the merits of RD and other ratemaking mechanisms
- RD scores well in advancing some longstanding ratemaking principles and objectives, but not so well for others
- Regulators, in one way or another, need to account for the effect of declining gas usage per customer in setting rates

The Challenge for Regulators -- *continued*

- In the end, regulators will need to address the following questions:
  - What are the objectives of ratemaking and their relative importance?
  - What ratemaking mechanism or group of mechanisms would *be most effective* in achieving those objectives?
  - Most essential, what ratemaking mechanism would be both fair to the utility and most beneficial to customers?

Contact

Ken Costello
Costello@nrri.osu.edu

NRRI Website
www.nrri.ohio-state.edu

ATTACHMENT G

H
Slip Copy

Mailed Date July 3, 2007

Adopted Date June 18, 2007

RE: THE INVESTIGATION AND SUSPENSION OF TARIFF SHEETS FILED BY PUBLIC SERVICE COMPANY OF COLORADO FOR ADVICE LETTER NO. 690-GAS.
06S-656G, C07-0568

COMMISSION ORDER APPROVING SETTLEMENT AGREEMENT WITH MODIFICATIONS

Colorado Public Utilities Commission

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B.

ADOPTED IN COMMISSIONERS' DELIBERATION MEETING June 18, 2007. 33

By the Commissioner

I. BY THE COMMISSION

A. Statement

1. This matter comes before the Commission for consideration of Advice Letter No. 690-Gas, filed by Public Service Company of Colorado (Public Service or Company) on December 1, 2006 and the related Stipulation and Settlement Agreement filed on May 31, 2007 (Stipulation). The signatories to the Stipulation are Public Service, Commission Staff (Staff), the Colorado Office of Consumer Counsel (OCC), and Seminole Energy Services, LLC (Seminole) (collectively, the Settling Parties). Atmos Energy Corporation (Atmos), Climax Molybdenum Company (Climax), Kinder Morgan, Inc. (KMI), and the United States Department of Defense - Federal Executive Agencies (Federal Agencies) are also intervenors in this docket but do not join in the Stipulation. At the hearing on the Stipulation Atmos and Climax opposed portions of the Stipulation.

2. In its direct case Public Service indicated that the principal changes contained in Advice Letter No. 690-Gas increase base gas rates for service and implement a partial decoupling rate adjustment mechanism for residential service. In addition to the rate changes, Public Service also proposed to implement a rate adjustment mechanism for non-weather related changes in average actual use per customer. This mechanism would adjust the rates of all residential customers to reflect actual average residential usage, normalized for weather affects, compared to the average customer consumption used to calculate rates in this case. Public Service proposed this adjustment mechanism as a three-year pilot program, applied to residential bills for service beginning July 1, 2008 and terminating June 30, 2011.

3. As part of the Stipulation, the Settling Parties[FN1] have agreed upon a settled revenue requirement, excluding the Gas Cost Adjustment (GCA), of $337,877,991 based upon the test year of the 12 months ended June 30, 2006, resulting in an increase in jurisdictional base rate revenues of $32,331,771, or 10.66 percent. The Settling Parties also agreed that Public Service shall be permitted to implement a Partial Revenue Decoupling Adjustment (PRDA) mechanism for the Residential Gas Class on a three-year pilot basis commencing October 1, 2008 and expiring September 30, 2011, subject to the Commission authorizing the continuance and/or extension of the program upon application of Public Service. The rider that takes effect October 1, 2008 shall reflect the affect of the change in use per customer on revenues for the period July 1, 2007 through June 30, 2008.

> FN1. With regard to the settlement of issues concerning revenue requirements, as set forth in Section II.A of this Stipulation, "the agreements and compromises reflected therein are those by and among Public Service, Staff and the OCC."Seminole joins in the resolution of the timing and requirement for Public Service to file its Phase II rate case, as described in Section II.C and takes no position on the particular resolution of the other issues herein. Accordingly, the use of the term "Parties" with respect to these sections of the Stipulation should be construed to mean that Seminole has no objection to the resolution specified therein.

4. Now, being fully advised in the matter, we find the rates established by the Stipulation are just and reasonable, and that the Stipulation is in the public interest, with the modifications discussed below.

B. Procedural History

5. On December 1, 2006, Public Service filed Advice Letter No. 690-Gas, along with pre-filed testimony in support of the Advice Letter. By Decision No. C06-1459, we suspended the proposed tariffs and the effective date of the tariffs for 120 days through April

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30, 2007. By Decision No. C07-0298 suspended the effective date for another 90 days through July 29, 2007.

6. In Decision No. C06-1459, we established the 30-day intervention period, which expired on January 16, 2007.

7. We held a prehearing conference on February 7, 2007 where we granted the petitions for intervention, approved the proposed procedural dates, as well as the proposed discovery procedures, and other procedural issues. The following parties filed timely notices or requests for intervention in this Docket: Atmos, Climax, OCC, Staff, KMI, Seminole, and the Federal Agencies. We granted the requests for intervention of Atmos, Climax, KMI, Seminole, and the Federal Agencies. Staff and OCC filed timely notices of intervention by right. Staff, OCC, and Seminole filed Answer Testimony and Exhibits. Public Service filed Rebuttal Testimony and Exhibits. All such testimony was timely filed.

8. In Decision No. C07-0452, we ordered that, should a settlement agreement be reached in this case, the parties to this matter were to file a comprehensive settlement agreement on or before the close of business on May 31, 2007.

9. On May 31, 2007, Public Service, Staff, OCC, and Seminole filed the Stipulation. Consequently, we held a scheduling conference on June 4, 2007 to determine how best to proceed to consider the Stipulation.

10. At the scheduling conference Atmos and Climax indicated they were not aware of the settlement negotiations that culminated in the Stipulation, and requested the Commission to order Public Service to hold a settlement conference among the non-signatories, or in the alternative require Public Service to declare it would conduct such a conference. Public Service agreed to hold a settlement conference on Tuesday, June 5, 2007.

11. By Commission Decision No. C07-0474, we set hearings on the Stipulation for 9:00 a.m. on Thursday June 7, 2007. A public comment hearing on the proposed Stipulation was also scheduled from 4:00 to 6:00 p.m. on Thursday June 7, 2007.

12. As part of that decision, we issued written questions concerning the Stipulation for witnesses to answer at hearing. We noted that the questions addressed only the minimum amount of testimony we wished to receive, and that additional questions may be propounded through cross-examination or by Advisory Staff and Commissioner questions during the course of the hearing. Hearings on the Stipulation commenced and concluded on June 7, 2007.

II. SETTLEMENT ISSUES

A. The $32.3 Million Rate Increase

1. The Parties' Initial Positions

13. In its direct case, Public Service originally sought to increase base rates by $41,540,530. On May 11, 2007, Public Service filed its rebuttal testimony and exhibits of nine witnesses responding to the various positions of the parties in answer testimony, which further supported its direct case, with the exception that the Company reduced its proposed return on equity from 11.00 percent to 10.75 percent, and adjusted its proposed revenue requirements accordingly. Pursuant to the adjustments reflected in its rebuttal case, Public Service revised its request for an increase to base rate revenues to $39,189,582, based on the Company's revised revenue requirement of $344,216,568 For example, as indicated *supra*, Staff recommended a base rate increase of $30,492,055 while the OCC recommended a base rate decrease of $2.9 million.

2. Settlement Resolution

14. The Settling Parties have agreed upon a settled revenue requirement, excluding the GCA, of $337,877,991 based upon the test year of the 12 months ended June 30, 2006. This results in an increase in jurisdictional base rate revenues of $32,331,771, or 10.66 percent. The Settling Parties have agreed to the specific resolution of certain disputed issues concerning revenue requirements, as set forth in Sections II.A.1 through II.A.6 of the Stipulation. A summary of the revenue requirement impact of the specific settled issues is reflected in Attachment A to the Stipulation. For the purpose

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of determining revenue requirements and to the extent an issue is not specifically addressed in the Stipulation or detailed in the supporting cost of service in Attachment B to the Stipulation, the Settling Parties agree to implementation of Public Service's proposal as to that issue, as reflected in the Company's rate case application originally filed on December 1, 2006, and corrected on February 12, 2007.

3. Commission Findings

15. In approving the $32,331,771 rate increase proposed in the Stipulation, we are required to analyze both the legal and policy implications of a rate proceeding. Legally, we look to the evidence in the record to arrive at a just and reasonable determination of the rates. In this case, the Settling Parties maintain that a significant amount of testimony exists to support the $32,331,771 million increase in rates. We agree. Based on the evidence in the record we find the $32,331,771 rate increase is just and reasonable.

B. Authorized Return on Equity (ROE)

1. The Parties' Initial Positions

16. Public Service originally sought an authorized rate of return on equity (ROE) of 11.0 percent in its direct case. However, as more fully described in the direct testimony of Public Service Witness Mr. Hevert, a reasonable range for Public Service's ROE is between 10.25 percent and 11.25 percent. In the rebuttal testimony Mr. Hevert updated his analyses, which include certain adjustments made in response to the suggestions of other witnesses in this proceeding, to arrive at a recommended ROE range from 10.25 percent to 11.25 percent, especially recommending a ROE of 10.75 percent. Public Service is currently authorized to earn a 10.50 percent return on common equity for its gas and electric departments. As articulated in answer testimony filed by the intervenors, there was much disagreement with the proposed 11.0 percent ROE.

17. For example, Staff advocated for a 10.00 percent ROE based on its calculated ROE range of 9.0 percent to 10.50 percent. OCC advocated for a 9.0 percent ROE based on its calculated range of 8.0 percent to 9.0 percent.

18. All of the witnesses who addressed the issue of ROE derived their estimates using a Discounted Cash Flow (DCF) approach, supplemented, in some cases, by analyses using the Risk Premium Approach, Capital Asset Pricing Model or Dividend Discount Model. The pre-filed testimony of the witnesses reflects differing opinions regarding the selection of the appropriate group of comparable companies to use in the DCF analysis, and the determination of dividend yields and growth rates. In addition, OCC witness Mr. Copeland recommended a lower ROE if the Commission approved Public Service's decoupling proposal.

2. Settlement Resolution- Opposed by Climax

19. For purposes of settlement, the Settling Parties agree that a fair and reasonable ROE for the Company's gas department is 10.25 percent.

20. At the settlement hearing, Climax voiced its opposition to the Stipulated 10.25 percent return on equity. Climax stated through its closing statement that Staff's original return on equity of 10 percent is a more appropriate level for the Commission to approve than the settled return on equity of 10.25 percent. In support of its position, Climax indicated that since Public Service filed its direct case in December of 2006, some seven months ago, the Company has agreed to reduce the requested ROE from the 11 percent it originally sought to the 10.25 percent that it now apparently says is a just and reasonable return on equity. In Climax's view, if trending means anything, then the required ROE to attract investors has been decreased quickly in the seven-month period.

21. Climax, in its closing statement, also stated that the protection afforded by partial decoupling for Public Service covers a reduction in customer usage for the residential class. As stated by Climax, residential use is roughly two-thirds of the Company's revenue stream, and it represents the most important revenue risk as test-

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ified by Mr. Brockett.

22. Climax points out that since December 1, 2006, the legislature has passed, and the Governor has signed House Bill (HB) 1037, which provides Public Service with the opportunity for full cost recovery of all its expenditures for energy efficiency which are prudently incurred, without the need for a rate case. HB 1037 also provides Public Service with a bonus, as Mr. Darnell testified, which cannot be counted by this Commission in determining the Company's rate of return, and in the ratemaking process. Added to both of these are the GCA and the impact on the recovery of commodity costs on a dollar-for-dollar basis.

23. Given all of these issues taken together, it is Climax's position that the settled rate of return for Public Service's gas business, ends up being essentially, risk free.

24. Climax indicates that it agrees with Staff witness Mr. Trogonoski's testimony addressing a 10 percent return on equity and finds it more fair, just, and reasonable than the Stipulation amount of 10.25 percent. Climax requests the Commission modify the Stipulation to establish Public Service's return on equity at 10 percent.

25. Climax goes on to indicate that one more telling aspect in support of its request to modify the ROE is Company witness Mr. Tyson's testimony that Public Service, for the year 2006, and across all of its ratemaking provisions, averaged about 75 percent recovery of what it requested in these proceedings. In response to a question asked by Chairman Binz, Mr. Tyson admitted that the settlement ROE represents about 82 percent of their requested revenue increase. Climax suggests that the Staff and OCC have agreed to settlement terms which result in ratepayers paying too much and Climax suggests that one way to reduce that burden is to establish the rate of return on equity at 10 percent.

3. Commission Findings

26. The terms of the Stipulation provide that the proposed ROE for Public Service is 10.25 percent. Public Service's current authorized ROE is 10.50 percent for its gas department, one quarter of a percent higher than what the Stipulation proposes. The ROE testimony establishes a range for determining an appropriate ROE between 9.0 and 11.25 percent. The proposed ROE falls within this range, therefore, we find it just and reasonable to approve the Stipulation's 10.25 percent ROE.

C. Cost of Debt

1. The Parties' Initial Positions

27. Public Service witness Mr. Tyson proposed a cost of debt of 6.38 percent, which was the embedded cost of long-term debt as of June 30, 2006. In his answer testimony filed on April 6, 2007, Staff witness Mr. Trogonoski expressed reservations about using the Company's embedded cost of debt as of June 30, 2006 because of the expected maturity on March 5, 2007 of a $100 million first mortgage bond with an interest rate of 7.11 percent. Mr. Trogonoski recommended a cost of debt of 6.29 percent taking into account both the maturity of the $100,000,000 first mortgage bond on March 5, 2007 and Public Service's anticipated reissuance of that debt at an interest rate of approximately 6 percent in July 2007. OCC witness Mr. Copeland recommended using the actual embedded cost of debt as of June 30, 2006.

2. Settlement Resolution

28. For purposes of the Stipulation, the Settling Parties agree that Public Service shall use a cost of debt of 6.29 percent to determine the weighted average cost of capital.

3. Commission Findings

29. No party to this rate case opposed this provision of the Stipulation. Therefore, we approve this portion of the Stipulation.

D. Capital Structure and Weighted Average Cost of Capital

1. The Parties' Initial Positions

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30. All witnesses who testified regarding the issue of capital structure agreed that Public Service's recommended capital structure was reasonable. The following table summarizes the Parties' recommendation with respect to capital structure:

Long-Term Debt	Equity
39.83%	60.17%

2. Settlement Resolution

31. For purposes of the Stipulation, the Settling Parties agree to the use of Public Service's actual capital structure as of June 30, 2006 and, excluding short-term debt, adjusted to include notes payable to subsidiaries as a part of long-term debt and to eliminate the effect of non-utility and subsidiary investments from the equity portion of the capital structure. The following table reflects the weighted average cost of capital that has been agreed to in the Stipulation by the Settling Parties:

	Weight	Rate	Wtd. Avg. Cost
Long-Term Debt	39.83%	6.29%	2.50%
Equity	60.17%	10.25%	6.17%
Total Cost:			8.67%

3. Commission Findings

32. No party to this rate case opposed this provision of the Stipulation. As indicated in the terms of the Stipulation based on the authorized ROE of 10.25 percent, a 60.17 percent equity ratio, and an average cost of long-term debt of 6.29 percent, the proposed return on rate base is 8.67 percent. Therefore, we approve this portion of the Stipulation without modification.

E. Depreciation

1. The Parties' Initial Positions

33. In its revenue requirements study, as supported through the rebuttal testimony of its witness Mr. Watson, Public Service proposed an allowance for depreciation expense that was based upon the depreciation rates last approved by the Commission in previous Public Service gas rate cases in Docket Nos. 00S-422G and 02S-315EG, referred to as the "existing depreciation rates." Through its witness, Mr. Majoros, the OCC recommended that the Commission reduce the Company's depreciation rates going forward to reflect a lower removal cost component of net salvage, and to amortize over 30 years the non-legal Asset Retirement Obligation (ARO) amounts currently included in accumulated depreciation for ratemaking purposes. This is based primarily on the adoption of Statement of Financial Accounting Standard No. 143, Accounting for Asset Retirement Obligations (SFAS 143). SFAS 143 defines "legal AROs" as obligations associated with the retirement of tangible long-lived assets that one is required to settle as a result of an existing or enacted law, statute, ordinance, written or oral contract, or by legal construction of a contract under the doctrine of promissory estoppel. "Non-legal AROs" are all removal costs not included in the "legal ARO" definition. Public Service's existing depreciation rates include recovery for total estimated future removal costs associated with utility assets. The recommendations of Public Service and the OCC regarding the proper depreciation rates for use in determining the Company's allowance for depreciation

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expense in this case are summarized in the table below:

	Party Proposal	Difference from: Public Service Proposal
	(Dollars in Millions)	
Depreciation Rate Change		
Public Service	44.5	
OCC	38.7	(5.9)
Amortization of "non-legal ARO" Regulatory Liability		
Public Service	0	
OCC	(4.6)	(4.6)
Total		
Public Service	44.5	
OCC	34.1	(10.5)

2. Settlement Resolution

34. For purposes of the Stipulation, the Settling Parties agree that Public Service shall continue to use the existing depreciation rates, as last approved by the Commission in Docket Nos. 00S-422G and 02S-315EG, for regulatory accounting purposes and for determining the depreciation expense allowance included in the settled revenue requirement in this case. Public Service is to include a footnote in its future annual FERC Form 2 filings disclosing the non-legal asset retirement obligation portion of accumulated depreciation for its gas utility operations. In conjunction with the current requirement for Public Service to submit to Staff a depreciation study on or before December 31, 2007 (*see* Decision No. C03-0670, p. 35, ¶ 107), Public Service agrees that it shall perform and submit a net salvage study as part this depreciation study and will serve a copy of the study on the OCC.

35. Public Service further agrees that if at any time in the future, the Company's natural gas utility operations in Colorado should become deregulated, Public Service shall make the necessary filings with the Commission prior to such deregulation to ensure that the Commission has an opportunity to review the Company's depreciation-related rates and accounts at the time of such deregulation to determine what orders it may need to enter with respect to those depreciation rates and accounts. Additionally, such Commission review may include, but not be limited to, the resolution of any regulatory issues concerning previously expensed depreciation, including any amounts of "Non-legal AROs" that may at the time be recorded as accumulated depreciation for ratemaking purposes. For purposes of the Stipulation, the amount of "non-legal AROs" is to be that amount that Public service has reported for financial reporting purposes pursuant to SFAS 143. The Settling Parties agree that nothing in this Stipulation shall limit the ability of any party to take whatever position it deems appropriate with respect to any depreciation-related issue that may arise as a

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consequence of any such filing. Public Service further agrees that it will neither propose nor support legislation that would remove these issues from the Commission's jurisdiction.

3. Commission Findings

36. No party to this rate case opposed this provision of the Stipulation, and the resolution of this issue is based in part on prior Commission decisions. As a result, we approve this portion of the Stipulation without modification.

F. Amortization of Environmental Clean-up and Other A&G Costs

1. The Parties' Initial Positions

37. In its direct case, Public Service proposed to amortize certain costs which had been deferred for accounting purposes and to include the annual amortized amount in its revenue requirement. These deferred costs relate to: (a) the environmental clean-up of a former Manufactured Gas Plant (MGP) site in Fort Collins, Colorado; (b) the closure of the Leyden Gas Storage Facility (Leyden); (c) certain gas pipeline inspection costs incurred under its Integrity Management Program (IMP); and (d) rate case expenses. The deferred amounts, the amortization period and the annual amortized amount proposed by the Company are as follows:

Deferred Costs	Total	Amortization Period	Annual Allowance
MGP Cleanup	$10,787,306	4 yrs.	$2,696,827
Leyden	$5,900,702	4 yrs.	$1,475,176
IMP costs	$2,788,904	3 yrs.	$929,635
Rate case expense	$1,289,170	2 yrs.	$644,585

38. Through the testimony of Public Service witness Mr. Willemsen, the Company proposed to continue the same deferred accounting, amortization and true-up of these costs, as approved by the Commission in Public Service's last gas rate case in Docket No. 05S-264G, and detailed below. Except for the costs incurred by Public Service in providing legal notice to its customers of this rate case, as discussed in the next section, no party submitted testimony challenging the level of any of the above deferred costs or the proposed amortization periods. Settlement negotiations revealed that the level of these deferred costs, particularly those associated with the Fort Collins MGP environmental clean-up costs have risen since Public Service's last gas rate case. Public Service notes that it has brought a contribution action against Schrader Oil Company and related parties seeking to offset a portion of costs it incurred to investigate and remove contaminated sediments from the Cache la Poudre River. The contribution action is scheduled for trial in 2008.

2. Settlement Resolution

39. For purposes of the Stipulation and to reduce the customer impact of the above deferred costs, the Settling Parties agree that the amortization period for the Fort Collins MGP environmental clean-up costs shall be extended from four years to five years. The resulting annual amortized amount for Fort Collins MGP environmental clean-up costs is $2,157,461, as detailed in Attachment B, Schedule 26, page 2 of 3 of the Stipulation. With this modification, the annual amortized expenses are included in the settled revenue requirement. If the amortization period applicable to any of these items expires prior to the effective date of rates resulting from Public Service's next rate case establishing a new revenue requirement, the Company will file an application to place into effect a negative rider that will reduce its base rates by the amount of the annual amort-

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ization expense for the amortization that had expired. With respect to the amortization of rate case expenses, the negative rider would go into effect on July 30, 2009. With respect to the amortization of IMP costs, the negative rider would go into effect on July 30, 2010. With respect to the amortization of Leyden costs, the negative rider would go into effect on July 30, 2011. With respect to the amortization of MGP environmental clean-up costs, the negative rider would go into effect on July 30, 2012. Any such negative rider would remain in place until the effective date of the rates resulting from Public Service's next gas rate case in which revenue requirements are determined.

3. Commission Findings

40. No party to this rate case opposed this provision of the Stipulation and the resolution of this issue is based in part on prior Commission decisions. As a result, we approve this portion of the Stipulation without modification.

G. Partial Revenue Decoupling Adjustment (PRDA)

1. The Parties' Initial Positions

41. In its direct case, Public Service proposed a residential class rate element identified as the PRDA that would be placed in Public Service's tariff, similar to the Company's current GCA and Demand Side Management Cost Adjustment clauses. The mechanism is designed to eliminate the impact of changes in customer use on Public Service's revenues and earnings. Specifically, the proposed mechanism would counter the financial impact of changes in customer use driven by factors other than weather, such as increased appliance efficiency, customer conservation efforts, and customer responses to price changes. The proposed mechanism would be implemented through a rider applied to the Company's base rate gas service revenues to compensate for the prior year's changes in weather-normalized use per customer. The rate adjustment would be updated annually to reflect both increases and decreases in weather-normalized use per customer.

42. Under this mechanism Public Service compares its weather-normalized sales during a month with the monthly weather-normalized sales in a base year -- such as the test year of the most recent rate case. The difference, whether positive or negative, is then multiplied by the distribution usage charge to derive the impact of changes in weather-normalized use on revenues. This difference between actual revenues collected and revenues based on no change in the weather-normalized demand is then collected or credited to customers through an adjustment to usage rates.

43. Public Service represented that residential gas use per customer has been declining at an average rate of 2.6 percent per year since the test period of July 2000 through June 2001. Public Service pointed to various demand side management (DSM) impacts that have reduced its revenues and earnings. Public Service proposed the PRDA to reduce this negative impact on the Company's shareholders by severing, or "decoupling", the connection between revenue, earnings and energy efficiency effects. Public Service pointed to movement nationally towards regulatory approval of full or partial decoupling rate mechanisms, as well as support from NARUC and environmental groups.

44. Public Service proposed a three-year pilot program of the decoupling adjustment mechanism, with a base period of May 1, 2007 to April 30, 2008. An initial PRDA is proposed to occur on June 1, 2008, with annual filings occurring for the following two years. For example, the June 1, 2008 PRDA would recover the shortfall in revenues due to non-weather-sensitive, per customer use between the base period and the previous 12 calendar months.

45. Staff witness Mr. Camp, in rebuttal testimony neither supported nor opposed the PRDA. Staff did recognize that a PRDA can help prevent earnings attrition, and that a PRDA eliminates the disincentive for Public Service's conservation efforts. Staff also noted that consumers will still retain the bulk of conservation savings through reduced gas commodity expenses. Staff pointed out that a PDRA could also mitigate regulatory lag which would result in fewer filed rate cases. Staff also approved of the fact that the proposed PRDA is

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symmetrical, allowing for capture of both increases and decreases on average weather normalized use per customer.

46. On the other hand, Staff argued that the benefit to consumers might still be uncertain, and the proposed PRDA, as applied only to the residential class, is discriminatory. Staff advocated that, because the PRDA is a departure from standard ratemaking practices in Colorado, the PRDA should be evaluated in a Phase II rate case. Staff finally observed that the proposed PRDA does not guarantee a rate of return for Public Service, nor does it provide Public Service with any revenue beyond the amount authorized by the rate of return aspect of this Phase I case. Staff contends that the PRDA tends to shift revenue shortfall risk from the Company and its shareholders to the residential customers.

47. Staff provided four options for the Commission to evaluate: approve the PRDA as proposed by Public Service, conditionally allow the PRDA subject to review in a Phase II case, defer a decision on the PRDA to a Phase II case, or deny Public Service's PRDA proposal. Staff, through the answer testimony of Mr. Dalton, also proposed slightly different calculation methodologies for the PRDA in the event we approve the PRDA, proposing that Public Service use a July-June base year. Staff also recommended that the PRDA, if approved, be capped at a 1 percent change in usage per customer.

48. OCC, in the Answer Testimony of Mr. Senger, argued that Public Service has not presented any significant data that requires such a dramatic change in the standard regulatory practice. Mr. Senger maintained that traditional rate of return regulation generally discourages "tracker" rate elements. OCC observed that the traditional regulatory process provides an incentive for utilities to become more efficient as the utility keeps such gains, at least temporarily, and that rate tracking adjustment mechanisms eliminate the utility's incentive to become more efficient. OCC believes that Public Service has historically had successful financial performance in spite of declining use per customer.

49. OCC posited that the "national trend towards decoupling" alluded to in Public Service witness testimony by Ms. Vincent, Mr. Hevert, and Mr. Brockett is much less universal than Public Service implies. OCC argued that the proposal advanced by Public Service shifts a significant amount of risk to customers, yet Public Service witness Mr. Hevert argued that it should not result in any benefit to the customers in the form of a lowered ROE. OCC's position was that potential revenue stabilization proposals should be considered at the same time, preferably in a combined Phase 1 and Phase 2 case, as other mechanisms such as increasing the fixed component of the bill, which cannot be considered in a Phase 1 proceeding. OCC also criticized the proposal as it inequitably applies to only one class of customers (Residential) and it is being called a "pilot" program, but it is not optional, like other pilot-type programs.

50. OCC recommended that the Commission reject Public Service's decoupling proposal. Alternately, OCC indicates that approval of decoupling should result in a lowered overall return to the Company and implementation should be delayed until the subsequent Phase 2 rate case, when residential customers can be compensated for the additional burden they will be bearing.

51. Public Service addressed many of the Staff and OCC concerns in its Rebuttal Testimony. Mr. Brockett of Public Service reiterated Public Service's concern that the Company recover a significant portion of its fixed costs through usage charges, thus declining use jeopardizes the Company's recovery of fixed costs. According to Public Service, the use of a historical test year in Colorado exacerbates the problem. A related problem is that Public Service has a disincentive to promote energy efficiency as long as it recovers fixed costs through usage charges. Further, Public Service does not believe that the PRDA mechanism represents a significant departure from traditional ratemaking. From an earnings standpoint, Public Service's response to a decrease in use per customer would be to take steps to reverse this trend. Yet one of Colorado's most critical public-policy goals is to promote energy efficiency, which obviously reduces use per customer. The interests of the shareholders in this case, in the view of Public Service, do not coincide with the broader public-policy goal. Public Service contends that the proposed PRDA

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mechanism is tailored to address this contradiction by truing up revenues for changes in weather-normalized use per customer, while maintaining the utility's risk for both changes in costs and changes in weather-related sales that are not directly affected by energy efficiency initiatives.

52. Public Service provided a national list of approved and proposed decoupling mechanisms in Mr. Brockett's testimony. The list includes companies that currently have decoupling mechanisms, and he points to other utility mechanisms that mimic revenue decoupling and/or revenue stabilization mechanisms of some type. The Company also noted that environmental organizations also support revenue decoupling and NARUC has issued a policy statement urging state commissions to consider revenue decoupling.

53. Public Service took the position that deferring the issue to a combined Phase I and Phase II rate proceeding would not add much value or insight. According to Public Service, as was the case with the Company's DSM adjustment clause, a decoupling adjustment can be assessed within the constraints of a Phase I case. Public Service argued that there is ample time to explore this issue without disadvantaging the Residential class. Public Service agreed with Staff's proposal to implement the first decoupling mechanism on October 1, 2008, and is willing to commit in this proceeding to filing a Phase II case on or before March 31, 2008. Public Service indicated it is willing to agree to Staff's proposed schedule for deriving, filing, and implementing the initial decoupling adjustment. Public Service also agreed with Staff's requirements for reports supporting its future filings on decoupling. Public Service agreed with much of Staff's recommendations on the mechanics of deriving the residential weather-normalized impacts. Public Service did not agree with Staff that the PRDA be capped at 1 percent. Public Service maintains that any weather-normalized technique that has been approved either in prior rate cases or this one be used in calculating the PRDA.

2. Settlement Resolution

54. The Settling Parties reached agreement to implement Public Service's proposal on decoupling from its direct case, with the exception of the reporting and calculation modifications proposed by Staff. Public Service agreed to make July 2007 through June 2008 as the base year when Public Service will begin accruing for the change in revenues based on the difference in weather normalized usage per residential customer. Beginning on August 15, 2008, Public Service is to file a tariff Advice Letter and accompanying reports as designated by Staff for a partial decoupling rate element that would be effective on October 1, 2008. This process will be repeated in years 2009 and 2010.

3. Commission Findings

55. We accept in part, and modify in part, the proposed decoupling mechanism. We have evaluated the testimony filed in this docket, along with the testimony received at hearing on the Stipulation. Based on that review, we find that the decoupling mechanism proposal has merit as a pilot program. Specifically, we find it is consistent with DSM initiatives. Additionally, the proposal aids in addressing the issue of fixed cost recovery for Public Service in an environment of declining average residential demand for natural gas, and could certainly reduce the number and cost of future rate cases. However, we reject the proposal to the extent that the proposal allows Public Service to recover all of the revenue associated with the partial decoupling proposal. Rather, we adopt the alternative mechanism described below.

56. We find that the entire risk associated with declining per customer use should not be assigned entirely to Public Service's residential customers. We expect that Public Service is aware of this decline in use per customer, and should be undertaking its own internal cost reduction, becoming more efficient through process redesigns and seeking more productive uses of its labor and capital resources. Becoming more efficient in the face of declining demand for an enterprise's product is rational economic behavior for a firm.

57. We understand the differences between a regulated

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monopoly and a fully deregulated firm, especially in terms of pricing. However, both categories of firms have the same ability, and incentive, to manage costs based on the market characteristics for its services. Further, the record in this docket demonstrates that Public Service continues to enjoy increased numbers of customers. The natural efficiency gains of economies of scale should provide a degree of offset to the revenue decreases caused by declining customer usage. Therefore we design a decoupling mechanism that divides the risk between ratepayers and Public Service.

58. Public Service will adjust rates each year through the decoupling rate adjustment mechanism to recover reduced weather-normalized revenues due to reduced usage per customer to the extent that revenue per residential customer declines more than 1.3 percent per year. This value was chosen as it equals one-half the historic rate of decline referenced in Public Service's testimony.

59. The weather-normalized use per customer will be compared annually to the corresponding test year value used to set rates initially. To the extent that the weather normalized use per customer has declined more than 1.3 percent per year since the test year, the rate rider in a given year will be designed to collect the associated revenues lost in excess of the 1.3 percent threshold (*i.e.*, lost revenues). We direct the parties in this case to hold technical meetings to define the process within the context of the original proposal of Public Service in this matter in order to implement our modifications to the decoupling mechanism.

60. To the extent weather normalized use per customer increases, Public Service will not be required to implement a negative rate rider. The year-to-year positive and negative changes in customer usage will be accumulated and used to calculate the revenue losses in excess of the threshold. But if weather normalized usage increases to the degree that Public Service would be required to implement a negative rider, the rider amount will be set to zero for that year's percentage.

61. An illustration of the proposed revised decoupling mechanism with the 1.3 percent threshold is provided below. This example is based on a threshold of 1.3 percent and uses the historical data provided by Public Service in Exhibit 35. The data in Exhibit 35 was a backcast of the impact of a decoupling adjustment if it had been in effect since 2001.

An Illustration: Revised Decoupling Mechanism Applied to Actual Historic Values

Year	Annual Use/ Customer	Annual Change	Annual Percent Change	Percent Change from Base	Threshold	Net Adjustment
2001	919					
2002	912	-7	-0.8%	-0.8%	1.3%	0.0%
2003	899	-13	-1.4%	-2.2%	2.6%	0.0%
2004	836	-63	-7.0%	-9.0%	3.9%	5.1%
2005	837	1	0.1%	-8.9%	5.2%	3.7%
2006	804	-33	-3.9%	-12.5%	6.5%	6.0%

62. In the example above, we assume that 2001 is the test year from which rates were derived. The decoupling rate adjustment for each year thereafter is designed to account for the cumulative impact of changes in use per customer relative to the base year of 2001. The column entitled "Percent Change from Base" illustrates that accumulation. Consistent with that method of calculation, the "Threshold" column contains the cumulative

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threshold of 1.3 percent for each year in this example. The final column, "Net Adjustment" is not the rider value itself, but rather the portion of the revenue decline of changes in weather-normalized use per customer that the decoupling mechanism will collect for Public Service. In the example above, the cumulative decline in revenue from the base year falls below the cumulative 1.3 percent threshold in 2002 and 2003, so there would be no collection of revenue from the decoupling mechanism in those years. In 2004, there is a 7.0 percent decrease in weather-normalized use per customer that pushes the cumulative decrease in usage above the 3.9 percent cumulative threshold, so Public Service is able to capture 5.1 percent of the revenue shortfall. That cumulative pattern extends into 2006 in this example.

H. Rate Case Expense

1. The Parties' Initial Position

63. In its direct case, Public Service included the cost of notifying customers of its rate case filed with the Commission. This expense item was to recover the direct mailing costs of the proposed rate changes to Public Service customers.

64. OCC, in rebuttal, objected to the $555,330 expense item. OCC contended that Public Service could have used a bill insert at a cost of $50,576. OCC argued that Public Service could have filed its rate case earlier, thus allowing it to place inserts into the cycle of mailed bills and meet the deadline of notifying all customers ten days before the end of this Commission's 30-day notice period.[FN2]

> FN2. This ten-day requirement allows any service recipient to file interventions in a timely manner.

65. In rebuttal, Public Service pointed out that the particular method of notice is at the option of the utility as specifically provided in § 40-3-104(1)(c)(I), C.R.S. Public Service noted that there is no requirement to use the least cost alternative to consumers. The options include the choice made by Public Service. Public Service has the ability to file for a rate change on 30 days' notice, and must notify customers 20 days prior to the effective date as filed. According to Public Service since it mails its bills in a cycle that uses every calendar day of the month, it could not meet the aforementioned timing requirement using a bill insert, so it used a special mailing instead.

2. Settlement Resolution

66. For the purposes of the Stipulation, the Settling Parties agree to Public Service's position retaining all customer notice expenses that were contained in this tariff Application. Public Service, Staff, and OCC agree to meet within 90 days following the effective date of the tariff to discuss various methods, including statutory and rule changes, to minimize the costs of future notifications.

3. Commission Findings

67. No party to this rate case opposed this provision to the Stipulation and the resolution of this issue is based in part on prior Commission decisions. As a result, we approve this portion of the Stipulation without modification.

I. Weather Normalization

1. The Parties' Initial Positions

68. In its direct case Public Service stated that Residential, Commercial, and Industrial customers were divided into three areas: Front Range, Mountain, and Western. Public Service calculated a ten-year average base load amount per customer for each area, comprised of August and September usage which represent the level of sales that is not weather sensitive. These base-load quantities were then removed from the test period adjusted sales to develop weather sensitive sales quantities. Public Service asserted that it normalized the weather sensitive quantities using the method recently approved by the Commission. Under the Commission-approved method, the most current National Oceanic & Atmospheric Administration 30-year normal (1971-2000) is

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updated by multiplying it by the ratio of the most current 30-year heating degree unadjusted data (1977-2006) to the unadjusted data for the 30-year period used for the most recent normal calculation (1971-2000). The weather normalization factor is the updated 30-year normal heating degree days divided by test period heating degree days.

69. In answer testimony OCC recommended two modifications. First, OCC asserted that the method should eliminate the double-counting of heating degree days (HDD) in June through December of 2005 in calculating normal HDD. Public Service included the HDD from June through December twice, once in the calculation of the 2005 HDD, and again in the calculation of the 2006 HDD, because complete 2006 information was not available at the time Public Service made its filing. OCC recommended updating the information to use the information from 2006 that is now known. Second, the weatherization method should recognize the downward trend in base load use in the adjustment calculation. Public Service used a ten-year average of the sales in August and September, and then annualized this number. OCC recommended using the data from the test period to calculate base load use per customer instead of using the ten-year average.

70. In rebuttal, Public Service argued that we should adopt a method that uses data that is available at the time a rate case is filed, and should reject the modifications recommended by OCC.

2. Settlement Resolution

71. The Settling Parties agree to implement the two weather normalization changes proposed by OCC witness Senger.

3. Commission Findings

72. In response to Commission questions at the settlement hearing regarding the future implications of this settlement issue, Public Service indicates that the Stipulation provides no guidance as to how it should file its next rate case. Though the Stipulation does not resolve this issue for the future, we agree that the two modifications recommended by OCC are reasonable, and adopt the settlement resolution for this issue of the Stipula- tion.

J. Phase II Rate Case Requirement

1. The Parties' Initial Positions

73. In its answer testimony, Seminole requests that the Commission require Public Service to file a Phase II rate case. Seminole witness Mr. Peter raised concerns that the Phase I rate increase would aggravate the lack of comparability between commercial sales rates and firm transportation rates, which the Commission recognized as an issue in Decision No. C06-0086 in Docket No. 05S-264G.

74. Pursuant to the settlement in 05S-264G, the last Public Service rate case, parties held workshops to address the comparability of sales and transportation rates, and Public Service agreed to make a filing as part of its next Phase II case. The Commission ordered Public Service to file a Phase II case within three years of the date of the decision in that last case, which resulted in a filing deadline of February 3, 2009. Public Service further agrees to the specific terms described above.

2. Settlement Resolution

75. Under the settlement in this case, Public Service agrees to file a Phase II rate case on or before March 31, 2008. Public Service also agrees that it will not use or support an imputed minimum system approach for inter-class cost allocation, it will file the results of using the Atlantic Seaboard method to allocate all non-customer-related fixed costs, and it will not propose or support any classification or inter-class allocation of costs that treats less than 25 percent of the non-customer-related costs as commodity costs.

3. Atmos's Response to the Settlement Resolution

76. In the settlement hearing on June 7, 2007, Atmos asserted that it was not included in these settlement nego-

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tiations, and requested that the Commission make two modifications to the Stipulation. First, the Commission should require Public Service to file, for information purposes, the results of using the Straight Fixed Variable method of cost allocation. Second, the Commission should strike the phrase "or support" from paragraphs b and d in the Phase II Rate Case section of the Stipulation.

77. Atmos states that it does not oppose the Stipulation with these modifications. Climax concurs with Atmos' recommendation.

4. Commission Findings

78. We find it reasonable to establish a March 31, 2008 Phase II rate case filing requirement. However, we find that the additional restrictions associated with the Phase II filing, provided in the Stipulation, are not supported by the record in this case. Further, we agree with Atmos that it is improper for Public Service to agree to such issues outside of a Phase II case, particularly when Atmos was not included in settlement negotiations in this case. We agree that the remedy proposed by Atmos results in a more balanced approach to the upcoming Phase II case, and we modify the settlement to adopt Atmos' recommendations here. Therefore, we require Public Service to file, for information purposes, the results of using the Straight Fixed Variable method of cost allocation. We strike "or support" from Paragraphs b. and d. of the Phase II Rate Case section of the Stipulation.[FN3]Paragraphs b. and d. are modified to read as follows:

> FN3. Chairman Binz dissents from the decision to strike "or support."

b. In such Phase II filing, Public Service will not use an imputed minimum system approach as the basis for its proposed inter-class cost allocation. However, the Company may use an imputed minimum system approach to support the development of its proposals relating to the service and facilities charges;
d. Public Service will not propose any classification or interclass allocation of costs that treats less than 25 percent of the non-customer-related costs as commodity costs.

K. Line Extension

1. The Parties' Initial Positions

79. In Answer testimony OCC raised concerns that Public Service's current line extension policy may cause current customers to subsidize new customers, at $75 million over six years, or over $12 million per year.[FN4]OCC recommended that the Commission require Public Service to track the growth-related plant and payments, and after sufficient data is collected, require the Company to file an application with the Commission defining the problem and proposing an equitable and economically rational solution.

> FN4.*See* Schechter Answer Testimony, pages 14 through 23.

80. In its Rebuttal Testimony, Public Service cited several problems with the OCC calculations reducing the amount not covered by refundable construction payments to $18.2 million.[FN5]Public Service recommended rejecting OCC's recommendations.

> FN5.*See* Niemi Rebuttal Testimony, pages 8 through 12

2. Settlement Resolution

81. The Stipulation does not directly address this issue, therefore the Settling Parties agree to implementation of Public Service's position,[FN6] leaving the current line extension policy without the modifications proposed by OCC.

> FN6. Stipulation, page 5

3. Commission Findings

82. We find that Public Service Witness Mr. Niemi adequately addressed the concerns raised by OCC with respect to the line extension issue and the questions we

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posed at the settlement hearing. Mr. Niemi explained that Public Service has taken steps to minimize any such subsidy, and we agree that no further action is appropriate for this issue. We adopt the settlement resolution for this issue; rejecting the recommendations made by OCC.

III. THE COMPLIANCE APPENDIX

83. Attached to this Order, as Attachment C, is a Compliance Appendix resulting from this case. The Commission has recently implemented a policy to use an internal database for tracking future filing requirements of our jurisdictional utilities. This Appendix enumerates the items to be completed, the party responsible for its completion, and the date by which the item must be completed.

IV. ORDER

A. The Commission Orders That:

1. The Commission approves the Stipulation and Settlement Agreement in Resolution of Proceeding (Stipulation), filed attached as Attachment A to this Order, with certain modifications as summarized below.

2. The Joint Motion to Approve the Stipulation filed on May 31, 2007 is granted in part, as detailed above.

3. Public Service Company of Colorado (Public Service) shall work with the other parties in this docket to implement the partial decoupling mechanism as discussed above.

4. As a part of the Phase II rate case filing required by the Stipulation, Public Service shall include, for information purposes, the results of using the Straight Fixed Variable method of cost allocation, as discussed above.

5. The words "or support" are stricken from paragraphs b and d in the Phase II Rate Case section of the Stipulation, as discussed above.

6. Public Service's Advice Letter No. 690-Gas is permanently suspended.

7. Public Service shall file, on not less than one day's notice to the Commission, tariffs consistent with this Order. Such tariffs shall be filed to become effective on July 30, 2007.

8. Public Service shall make all filings in compliance with this Order as indicated in Attachment C to this Order.

9. The 20-day period provided for in § 40-6-114, C.R.S., within which to file applications for rehearing, reargument, or reconsideration begins on the first day after the effective date of this Order.

10. This Order is effective on its Mailed Date.

B. ADOPTED IN COMMISSIONERS' DELIBERATION MEETING June 18, 2007.

Decision No. C07-0568-E

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

DOCKET NO. 06S-656G

RE: THE INVESTIGATION AND SUSPENSION OF TARIFF SHEETS FILED BY PUBLIC SERVICE COMPANY OF COLORADO FOR ADVICE LETTER NO. 690-GAS.

ERRATA NOTICE COMMISSION ORDER APPROVING SETTLEMENT AGREEMENT WITH MODIFICATIONS

Errata mailed July 11, 2007

Original Decision No. C07-0568 mailed July 3, 2007

Correct the header of Decision No. C07-0568 on page 2 and subsequent pages, replacing "Decision No. C07-0474" with "Decision No. C07-0568".

THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

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Doug Dean, Director Dated at Denver, Colorado this 11th day of July, 2007.

END OF DOCUMENT

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ATTACHMENT H

Agenda Date: 10/12/06
Agenda Item: 2C

STATE OF NEW JERSEY
Board of Public Utilities
Two Gateway Center
Newark, NJ 07102
www.bpu.state.nj.us

DIVISION OF ENERGY

IN THE MATTER OF THE PETITION OF SOUTH JERSEY GAS COMPANY FOR AUTHORITY TO IMPLEMENT A CONSERVATION AND USAGE ADJUSTMENT	DECISION AND ORDER APPROVING STIPULATION DOCKET NO. GR05121019
IN THE MATTER OF THE PETITION OF NEW JERSEY NATURAL GAS COMPANY FOR THE IMPLEMENTATION OF A CONSERVATION AND USAGE ADJUSTMENT	DOCKET NO. GR05121020

(SERVICE LIST ATTACHED)

BY THE BOARD:[1]

On December 5, 2005, New Jersey Natural Gas Company ("NJNG" or "Company") and South Jersey Gas Company ("SJG" or "Company") (collectively, "Companies") each filed a petition with the Board of Public Utilities ("Board") requesting approval of the implementation of a Conservation and Usage Adjustment ("CUA") Clause within its tariff on a five-year pilot program basis. As described by the petitions, the CUA's primary purpose was to separate the Companies' margin recoveries from throughput and to adjust margin recoveries for variances in customer usage, enabling the Companies to aggressively promote conservation and energy efficiency by their customers. The Companies' petitions were accompanied by the testimony of Daniel P. Yardley, Principal, Yardley Associates, in support of the proposal. Additionally, the NJNG filing included the testimonies of Laurence M. Downes, Chairman and Chief Executive Officer, New Jersey Resources ("NJR"), and Thomas J. Massaro, Vice President, Corporate Strategy and Business Intelligence, NJR Service Company. The SJG filing included the testimonies of Edward Graham, Chairman, President and Chief Executive Officer, South Jersey Industries and President and CEO of SJG, and Bonnie Bornstein, Vice President, Customer Services, SJG. Various exhibits also were submitted with the testimonies.

The proposed CUA mechanisms would separate margin recoveries from throughput by modifying the existing Weather Normalization Clause ("WNC"), Rider D to the tariff for NJNG, and the Temperature Adjustment Clause ("TAC"), Rider F for SJG (sometimes referred to collectively as "Weather Clauses"). As currently structured, these BPU-approved clauses are mechanisms that collect or credit margins based on customer usage changes attributable to variances between actual and normal weather and are complementary to the base rates. The proposed CUA tariffs

[1] Commissioner Christine V. Bator recused herself on this matter due to a potential conflict of interest.

would normalize the Companies' margin recoveries for variances in weather as well as other factors affecting usage, including customer conservation. For NJNG, the operation of the CUA as proposed is similar to its WNC. The proposed baseline usage was calculated by class based on historic consumption and was stated on a per-customer basis. For SJG, the operation of the CUA as proposed is similar to its TAC. SJG's proposed baseline customer usage levels are equivalent to the average monthly use per customer established in its base rate proceeding, completed in July 2004 (Docket No. GR03080683). The proposed baseline usage was calculated by class based on historic consumption and was stated on a per-customer basis. The proposals provided for an annual calculation by each Company of the changes in customer usage compared with the baseline established for each customer class. This calculation would reflect changes attributable to weather and non-weather drivers, including customer conservation. The margin impact associated with changes in aggregate usage compared to the baseline would then be calculated and included in the modified Rider D for NJNG and Rider F for SJG. The changes would be calculated monthly using booked sales and customer count data, and then aggregated for the year. The resulting impact would be collected from or credited to customers over a subsequent annual period.

The Companies asserted that through the implementation of the CUA, the current incentive for the Companies to increase throughput from existing customers in order to enhance the opportunity to earn their rates of return utilized to set rates would be eliminated. Instead, the Companies maintained that through the CUA, their interests would be more appropriately aligned with those of their customers since any customer savings through conservation would not have a negative impact on the Companies' financial performances. The Companies claimed that the promotion of additional initiatives that capitalize on various channels for reaching customers available to the utilities would be encouraged through the implementation of the CUA tariff. Therefore, an integral aspect of the CUA proposals would be the utilities' aggressive promotion of customer-specific programs to encourage both conservation and energy efficiency. According to the Companies, their proposed CUA would be consistent with the State's Clean Energy Program ("CEP") but would offer targeted and personalized messages to consumers not otherwise offered by the CEP, and the CUA would thereby reinforce and enhance CEP initiatives and messages. An additional aspect of the proposed CUA programs involved a major alteration of business processes in each Company since the focus would no longer be towards increasing burner tips. To support the promotion of such programs, each Company would institute internal training and programs to educate their employees on the Companies' revamped focus.

On January 25, 2006, a motion to intervene was filed with the Board on behalf of Direct Energy Services, LLC. Subsequently, by way of letter dated July 5, 2006, the motion was withdrawn.

Two public hearings on the NJNG filing were held in Freehold Borough, New Jersey on July 13, 2006 in order for members of the public to present their views on the CUA proposal. Alexander Stern, BPU Legal Specialist, presided. No members of the public appeared. Similarly, two public hearings on the SJG filing were held in Voorhees, New Jersey on July 13, 2006 in order for members of the public to present their views on the CUA proposal. Edward Beslow, BPU Legal Specialist, presided. No members of the public appeared.

Representatives of NJNG, SJG, Board Staff and the Department of the Public Advocate, Division of Rate Counsel (formerly Division of the Ratepayer Advocate) ("Rate Counsel"), the only parties in these proceedings, met on several occasions to discuss the Companies' proposals. In response to requests from Board Staff and Rate Counsel, the Companies also provided additional information by way of discovery responses. As a result of the discussions and information exchanges, the parties reached agreement as set forth in the attached Stipulation of Settlement ("Stipulation") and a letter of clarification dated October 6, 2006 ("clarification letter"), also attached hereto. By the

clarification letter, the Companies addressed and all parties agreed to two points of clarification requested by Rate Counsel, and all parties agreed to the terms of the Stipulation.

As provided in the Stipulation, the parties agreed that, pursuant to N.J.S.A. 48:2-21.1 and pending the filing described in paragraph 33(d) of the Stipulation, the CUA will be modified and implemented on a three year pilot basis and will be referred to as the Conservation Incentive Program ("CIP") to more accurately reflect the intent and focus of the program. As described in further detail in the Stipulation and this Order, the CIP will be an incentive-based program that: requires the Companies to implement conservation programs to be funded by their shareholders and designed to aid customers in reducing their costs of natural gas and to reduce each utility's peak winter and design day system demand; requires the Companies to reduce gas supply related costs; and, commencing in the 2007-2008 CIP year, allows the Companies to recover from customers certain non-weather margin revenue losses limited to the level of gas supply cost savings achieved. Certain capacity related gas supply cost reductions will begin during the 2006-2007 Basic Gas Supply Service ("BGSS") rate year and will not be used to offset any margin revenue losses in the initial CIP year. BGSS customers will thereby receive an immediate benefit from the program beginning in the 2006-2007 BGSS rate year. The Stipulation, with the October 6, 2006 letter's clarifications, includes terms and conditions summarized as follows:

1 NJNG and SJG will implement incremental conservation programs designed to aid customers in reducing their costs of natural gas and to reduce each utility's peak winter and design day system demand. A complete description of the programs is attached to the Stipulation as Exhibits A and B for NJNG and SJG, respectively. The programs are not to replicate existing programs of the Office of Clean Energy and may be implemented prior to the effective date of the CIP tariffs. The Companies will assess the need to develop and implement future programs, if appropriate, that would deliver additional benefits to customers and further reduce energy costs in New Jersey. If NJNG and/or SJG determine that the introduction of a new program would be beneficial to the CIP program and customers, the Company will provide BPU Staff and Rate Counsel with relevant documentation regarding the proposal. By February 1, 2007, the Companies will provide the parties with analyses, to be funded with shareholder monies, of an inverted BGSS pricing structure and advanced metering and/or control equipment.

2. The Companies' shareholders will pay for the enhanced conservation programs. Each Company will provide quarterly reports to BPU Staff and Rate Counsel documenting expenditures for these programs. NJNG will provide $2 million for program costs no later than 10 days from the date of Board approval of the Stipulation. SJG will provide $400,000 for each year of the pilot program as costs are incurred, with any unexpended amount being carried over and added to the amount to be spent in the following year, and any carry-over balance remaining at the end of the program being credited to SJG's BGSS clause. Should costs of the CIP exceed the initial funding levels established in the Stipulation, NJNG and SJG will continue to fund 100 percent of such program costs. The Companies also agree that costs for any employees whose work is more than incidental to the CIP will be charged to the CIP program costs, and such costs will be treated "below the line" for ratemaking purposes.

3. NJNG will return to its customers, through the Societal Benefits Charge ("SBC"), an estimated $4.9 million in the Market Development Fund ("MDF") in the month that the Board issues an Order approving the Stipulation. Additionally, NJNG will return to customers any remaining balance in the MDF through the SBC after giving effect to the monetary impact from the operation of the MDF through October 31, 2006 in November 2006 except for the balance to be determined in the pending request in Docket No. GR05100846. SJG will return to its customers through the BGSS Clause the full amount, estimated at $4.1 million,

from the Transitional Energy Facilities Assessment ("TEFA") in the month that the Board issues an Order approving the Stipulation.

4. The Companies will make annual CIP filings, based upon seven months of actual data and five months of projected data, with a June 1 filing date, that will document actual results, perform the required CIP collection tests and propose the new CIP rate. Any variances from the annual filings will be trued up in the subsequent year. As part of the annual CIP filings, the Board may review any aspect of the Companies' programs, including, but not limited to, the sufficiency of program funding. The Board may take such actions as it determines to be necessary and appropriate.

5. The CIP Tariff Riders for NJNG and SJG are attached to the Stipulation as Exhibits C and D, respectively. The CIP tariffs include return-on-equity ("ROE") limitations on recoveries from customers for both the weather and non-weather related components. NJNG agrees to reduce the ROE cap utilized in the CIP tariff to 10.5 percent effective on October 1, 2006. Additionally, NJNG agrees that if the Company has not filed for a review of its base rates by October 1, 2008, other than the review in paragraph 33(d) of the Stipulation, the applicable ROE cap utilized in the CIP tariff will be reduced to 10.25 percent. SJG will maintain the ROE cap utilized in the CIP tariff of 10.0 percent. Recovery of the margin impact associated with non-weather related changes in customer usage also will be limited to the level of BGSS savings achieved pursuant to the terms set forth in Section IV of the Stipulation and discussed below.

6. The residential heating benchmark for NJNG shall be 1,113 therms on an annual basis. The residential heating benchmark for SJG shall be 914 therms on an annual basis. The benchmarks for the other customer groups will remain as proposed by the Companies and are reflected in Exhibits C and D attached to the Stipulation.

7. The CIP Tariffs will reflect a $0.0000 rate for the period October 1, 2006 through September 30, 2007. The terms of the existing Weather Clauses for NJNG and SJG will be suspended as of October 1, 2006. Any credit or surcharge associated with the operation of the existing Weather Clauses up to and including the 2005-06 Winter will be applied to customer bills consistent with the terms of those clauses. Further, the provisions relating to over and under-recovery of prior period rate credits or charges will continue until such time as there is no remaining balance to be refunded or surcharged to customers.

8. The enhanced conservation programs and CIP adjustment tariffs will be implemented on a pilot program basis. Subject to the provisions of paragraphs 21 and 33(d) of the Stipulation, the pilot term will be three years beginning with the October 2006 billing cycle and ending with the September 2009 billing cycle.[2] Included in the pilot is a comprehensive review and evaluation process to determine the benefits to customers and the Companies during the initial term. The Board retains full authority to extend, modify or terminate the pilot program upon the end of the three year initial term. If a Board order relative to the continuation of the CIP is not issued by October 1, 2009, the pilot program will continue for up to one additional year or until the issuance of a Board order. Should no Board order be issued as of October 1, 2010, the pilot program will terminate subject to the conditions in paragraph 31 of the Stipulation.

[2] Under the CIP tariffs, the margin impacts of changes in customer usage are reflected on customer bills as a credit or surcharge in the subsequent year. Therefore, the implementation of the CIP tariffs on a pilot basis will result in credits and/or surcharges established on an annual basis for the annual periods beginning October 1 of 2007, 2008 and 2009.

9. NJNG and SJG will undertake a comprehensive evaluation of the effectiveness of the initial two years of the pilot program, beginning no later than November 1, 2008 and including an assessment performed by an independent third-party. The evaluation will include, but not be limited to, an analysis of the Companies' average use per customer per degree day for each CIP group pre- and post-CIP implementation. The Companies will also endeavor to create a comparison of the change in the trend in average customer usage as compared to a peer group consisting of the customers of other New Jersey local distribution companies that did not implement a CIP-type mechanism during the same time period. The Companies agree to work with the parties to determine any other relevant measures. Costs for this independent evaluation will be paid for with shareholder monies. The results of the evaluation will be documented and submitted to the parties for review on or before January 15, 2009. Upon circulation of the evaluation, the parties agree to meet to discuss whether to extend, modify or terminate the pilot program. No later than April 1, 2009, NJNG and SJG will each file a proposal with the Board concerning the future disposition of the pilot program.

10. If the pilot program terminates, the Weather Clause of each Company will be reinstated as of the date of the CIP's termination, in the same form as existed immediately prior to the implementation of the CIP tariffs. Upon reinstatement, the Weather Clauses will reflect a rate of $0.0000. Any credit or surcharge associated with the operation of the CIP tariffs for the final year of the pilot will be applied to customer bills in the subsequent year.

11. The parties agree that reductions in customer usage provide opportunities to reduce peak-related demand costs and to utilize lower cost commodity supplies. As such, additional BGSS savings resulting from reductions in customer usage, as described more fully in the Stipulation, will offset any recovery of non-weather related margins through the CIP tariffs and such verified savings will limit the level of non-weather CIP recoveries. For each year of the pilot program, the non-weather related CIP surcharge, if any, will be compared to the BGSS gas cost savings during the period that the surcharge would be in effect. Specifically, the impact of non-weather related changes in customer usage for the period October 1, 2006 through September 30, 2007 will be eligible for recovery if the BGSS savings to be realized for the period beginning October 1, 2007 is equal to or greater than the non-weather value of the CIP surcharge amount, and similar comparisons will be made for the pilot program's other years. The methodology employed to calculate the non-weather related CIP surcharge, if any, is delineated in paragraph 33(a) of the Stipulation. If the non-weather related CIP recovery is less than or equal to the level of available gas cost savings, the amount will be eligible for recovery through the CIP tariffs. Any portion of the non-weather CIP value that exceeds the available gas cost savings will not be recovered in the current period and will be deferred up to three years and subject to an eligibility test in the subsequent period. Deferred CIP surcharges may be recovered in a future period to the extent that available gas cost savings are available to offset the deferred amount. If the pilot is terminated after the initial period, any remaining deferred CIP surcharges will not be recovered. The value of any BGSS savings during one year in excess of the non-weather CIP value cannot be carried forward for use in future year calculations.

12. BGSS savings during the period prior to October 1, 2007 will not be reflected in the determination of CIP surcharge eligibility for the pilot program's initial year. Customers will receive the benefit of an additional year of BGSS gas cost savings.

13. NJNG and SJG will initiate contract restructurings and/or purchasing practices designed to benefit customers through lower BGSS costs. The resulting BGSS gas cost savings will be verified on an annual basis and be available to offset non-weather-related CIP surcharges. Categories of potential BGSS gas cost savings will include, but not be limited to: (i.)

reductions in the fixed capacity cost of citygate capacity effectuated through the release of capacity to an affiliate or non-affiliate and/or other means of reducing citygate capacity on a long-term basis, i.e. for periods of at least one-year; (ii.) fixed cost savings associated with avoided increases to citygate deliverability; and (iii.) reductions in the commodity cost of gas supply effectuated through purchasing strategies implemented as a result of reductions on peak day and winter demand.

14. The Companies will provide supporting documentation regarding the terms and merits of any future transactions that generate BGSS savings and that are to be considered for the savings calculation. Initial BGSS savings for the three year period beginning October 1, 2007 and ending September 30, 2010 are demonstrated in Exhibits E and F attached to the Stipulation for NJNG and SJG, respectively. Additional savings will only be counted within the BGSS savings calculation after consultation with and agreement by the BPU Staff and Rate Counsel about BGSS savings transactions pursuant to paragraph 33(c) of the Stipulation. The savings calculations and the eligibility of such savings for determining non-weather related CIP recovery will be further evaluated in the immediately succeeding BGSS proceeding for each Company and be subject to Board approval. Portfolio restructuring mandated by SJG's Global Settlement at Docket No. GR03080683 and SJG's Liberty Audit's recommendation GS-15 at Docket No. AX04040277 shall not be considered when determining BGSS savings. SJG intends to have a peak day study performed by a third party to begin within thirty (30) days of the October 6, 2006 letter of clarification, which will, among other things, evaluate the gas supply portfolio. Portfolio restructuring recommended as a result of this study will be used by SJG to propose guidelines for determining savings eligible for SJG CIP purposes and those guidelines will be included in its 2007 CIP filing for the consideration of the parties and BPU approval. SJG will submit a report to Rate Counsel and BPU Staff, including recommendations, at the conclusion of the study.

15. NJNG and SJG will each make filings by June 1, 2007 seeking final Board review and approval of its rates with the proposed CIP tariff and will include information as set forth in the Stipulation at paragraph 33(d) to allow the Board to determine if such rates are just and reasonable.

16. SJG will withdraw its proposal to seek approval of the capacity and portfolio enhancement mechanism, which it proposed in its 2005-2006 BGSS proceeding, Docket No. GR05060496 and reserved the right to pursue in the SJG Global Settlement, Docket No. GR03080683.

DISCUSSION AND FINDINGS

Having carefully reviewed the Stipulation and clarification letter of the parties in this proceeding, the Board **HEREBY FINDS** that the Stipulation as clarified is reasonable, in the public interest and in accordance with law. With the CIP and the possible recovery of non-weather-related margin losses, the utilities have represented that they will actively promote conservation and energy efficiency by their customers through programs funded by their shareholders. The programs are not to replicate existing CEP programs and are to include, among other things, customized customer communications and outreach built upon the utilities' relationships with their customers. While not replicating existing CEP programs, the CIP programs include initiatives which promote customers' use of CEP programs through consistent messaging with the CEP programs. At the same time, by limiting non-weather-related CIP recovery by gas supply cost reductions, in addition to an earnings cap, the CIP gives recognition to the nexus between reductions in long term usage and reductions in gas supply capacity requirements. By limiting any non-weather CIP recovery to offsetting gas supply cost reductions, the CIP does not just provide the utilities with a mechanism

for rate recovery but ensures that the CIP results in an appropriate, concomitant reduction in gas supply costs borne by customers. In this way, customers taking BGSS will not incur any overall net rate increases arising from non-weather related load losses. There also will be an immediate reduction in gas supply capacity related costs commencing in the 2006-2007 BGSS rate year while any recovery of non-weather related margin revenue losses will not commence until the 2007-2008 BGSS rate year. Furthermore, initial approval of the CIP on a three year pilot basis pending the further review provided by paragraph 33(d) of the Stipulation, will provide the Board and parties with an opportunity to further assess the impact, efficacy and merits of the CIP.

For the foregoing reasons, pending and subject to the filing seeking final Board review and approval of each Company's rates with the proposed CIP tariff, as set forth in the Stipulation at paragraph 33(d), the Board **FINDS** that implementation of the CIP reflects a reasonable balance of the interests of the various parties and should support current public policy concerning conservation and energy efficiency. Accordingly, the Board **HEREBY ADOPTS** the Stipulation, as clarified by the October 6, 2006 letter, in its entirety, incorporating the terms and conditions as if fully set forth at length herein. Pursuant to the terms of the Stipulation, the Board **HEREBY DIRECTS** that within 10 days of the date of this Order: NJNG and SJG shall file revised tariff pages; NJNG shall provide a letter from its authorized representative certifying that it has returned to its customers, through the SBC, the Market Development Fund monies as described in paragraph 18 of the Stipulation; and SJG shall provide a letter from its authorized representative certifying that it has returned to its customers, through the BGSS Clause, the monies from its Transitional Energy Facilities Assessment as described in paragraph 19 of the Stipulation.

DATED: 12/12/06

BOARD OF PUBLIC UTILITIES
BY:

JEANNE M. FOX
PRESIDENT

FREDERICK F. BUTLER
COMMISSIONER

CONNIE O. HUGHES
COMMISSIONER

JOSEPH L. FIORDALISO
COMMISSIONER

I HEREBY CERTIFY that the within document is a true copy of the original in the files of the Board of Public Utilities

ATTEST:

KRISTI IZZO
SECRETARY

ATTACHMENT I

Slip Copy July 17, 2009

APPLICATION OF THE SOUTHERN CONNECTICUT GAS COMPANY FOR A RATE INCREASE
08-12-07

DECISION

Connecticut Department of Public Utility Control

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By the following Commissioners: Anthony J. Palermino, Amalia Vazquez Bzdyra, Kevin M. DelGobbo

I. INTRODUCTION

A. BACKGROUND OF PROCEEDING

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By application dated January 20, 2008, pursuant to §§ 16-19, 16-19b and 16-19kk of the General Statutes of Connecticut (Conn. Gen. Stat.), and Order No. 3 in the Department of Public Utility Control's (Department or DPUC) Decision dated October 24, 2008 in Docket No. 08-07-10,DPUC Review of Overearnings for The Southern Connecticut Gas Company (Overearnings Decision), The Southern Connecticut Gas Company (Southern or Company) filed a rate case application (Application). The Company initially sought Department approval of its proposed rates designed to produce revenues, on an annualized and normalized basis, of $493.1 million, or $50.1 million in excess of those being produced by the Company's present rate structure, or approximately 15.2% above firm revenues produced by the present rates. On May 18, 2009, in response to various updates and corrections during the evidentiary process, the Company revised its rate request to $34,179,309 or an approximately 9.6% increase to current base rates. The reduction to the revenue request was due primarily to the approximately $61 million decrease to the Company's projected gas costs and to the decline in the related supplemental supply costs. Response to Interrogatory GA-2 Corrected, Attachments 1 and 2.

Southern's filing included not only a traditional rate case (Rate Case) but also an overearnings review period (ERP) associated with the Overearnings Decision. In the Overearnings Decision, the Department ordered the Company to reduce rates on a prospective basis by approximately $15.1 million through a line item credit of $0.0621 per ccf on customers' monthly bills. The Company applied this credit to all firm customers, including firm transportation (FT), for usage occurring on or after October 24, 2008. Pursuant to Conn. Gen. Stat. § 16-19(g), the Company requested an offsetting surcharge to the interim rate credit. The Company claimed the rate credit ordered in the Overearnings Decision was inapt and not required.

On June 30, 2009, the Department issued a final Decision in Docket No. 08-12-06,Application of Connecticut Natural Gas Corporation for a Rate Increase. That natural gas company rate Decision, heard pursuant to Conn. Gen. Stat. § 16-19, near in date and of a sister affiliate of Southern addressed many common issues and regulatory policies as this Decision. Both Dockets were heard under a consistent set of statutes. However, a separate panel of Commissioners heard this Decision. Each Docket's record is unique. As a result, the facts, analyses and logic employed in this Decision may differ. This Decision stands on its merits alone. Though superficially tempting, it would be inappropriate to use either Decision to find fault or support in the other. In administrative law, the Department need not strictly adhere to *stare decicis*. See, Greenwich v. Department of Public Utility Control, 219 Conn. 121, 127; B. Schwartz, Administrative Law, 620 et seq. (2d Ed. 1984).

B. CONDUCT OF PROCEEDING

By Notice of Hearing dated March 2, 2008, pursuant to Conn. Gen. Stat. §§ 16-11, 16-19, 16-19b, 16-19e and 16-19kk, and Regulations of Connecticut State Agencies (Conn. Agencies Regs.) § 16a-35-49, the Department held a public hearing on this matter on April 8, 2009 at its offices, Ten Franklin Square, New Britain, Connecticut. The hearing continued at the offices of the Department on April 9, 13, 14, 15, 16, 20, 21 and May 7, 2009. By Notice of Continued Hearing dated May 11, 2009, the hearing was continued on May 20, 2009.

Hearings for public comments only were also held on April 16, 2009 at the Bridgeport Town Hall City Common Council Chambers, 45 Lyon Terrace, Bridgeport, Connecticut, and on April 22, 2009 at the New Haven Hall of Records, G2-Hearing Room 200, Orange Street, New Haven, Connecticut. On May 27, 2009, the Department issued a Notice of Close of Hearing for the instant case.

C. PROVISION OF WORKPAPERS AND SUPPORTING DETAIL

Southern requested that the Department provide the supporting detail for the adjustments in the draft Decision used to determine Southern's revenue requirement. Written Exceptions, p. 2. In reaching its Decision herein, the Department relied solely on the record evid-

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ence.

As a general proposition, Conn. Gen. Stat. §1-210 requires that all records maintained by a public agency are public records and shall be disclosed. However, section (b)(1) of that statute states that the general proposition shall not be construed to require disclosure of preliminary drafts or notes provided the public agency has determined that the public interest in withholding such documents clearly outweighs the public interest in disclosure. Thus, disclosure in this case requires the Department to perform a balancing of interests test. In determining rights and privileges, the Department functions in a quasi-judicial manner. The July 10, 2009 Draft Decision is part of a complex deliberative process. As a part of that deliberative process, Southern (as well as other parties) were given an opportunity (pursuant to Conn. Gen. Stat. §4-179) to file Written Exceptions and present Oral Arguments before the final Decision is entered. The key balancing factors for the Department to take into account is whether the Company is disadvantaged in filing its Written Exceptions by virtue of not having access to the deliberative staff's workpapers and whether that disadvantage outweighs the pubic interest in maintaining and protecting the deliberative administrative process.

As to the first consideration of the balancing test, the Department strongly believes that the 187 page Draft Decision is detailed in the extreme as to how the Department weighed all pieces of record evidence. The Department did not rely on any new information, data or methods in its calculations or analysis. The Draft discusses in explicit detail the reasoning for all of its conclusions and adjustments. Thus, the Department believes that the Company could fully discern all reasoning that went into each adjustment and was fully armed to state where it believed error may exist and comment on the Department's reasoning and analysis. Southern's 100 pages of detailed Written Exceptions demonstrates that Southern could cogently comment on the Draft Decision without Department workpapers.

As to the second part of the balancing test, the United States Supreme Court in United States v. Morgan, 313 U.S. 409, 422, 61 S. Ct. 999, 85 L. Ed. 1429 (1941) has stated: "Just as a judge cannot be subjected to such a scrutiny, ... so the integrity of the administrative process must be equally protected (wherein the Secretary of Agriculture was shielded from examination regarding the process by which he reached conclusions of a ratemaking order since the proceeding before him had the quality resembling that of a "judicial proceeding" and integrity of the administrative process was paramount. This view was adopted in Connecticut in Welch v. Zoning Board of Appeals, 158 Conn 208 (1969). Accordingly, the Department believes that maintaining the integrity of the deliberative process outweighs the interest in disclosure in this instance. For the foregoing reasons, the Department will not provide workpapers or further supporting detail used to prepare the Department's De- cision.

D. PARTIES AND INTERVENORS

The Department recognized the following as Parties to this proceeding: The Southern Connecticut Gas Company, 855 Main Street, Bridgeport, Connecticut, 06604-4918; Office of Consumer Counsel (OCC), Ten Franklin Square, New Britain, Connecticut 06051; Office of Policy and Management, 450 Capitol Avenue, Hartford, Connecticut 06106; Department of Economic and Community Development, 505 Hudson Street, Hartford, CT 06106; Department of Environmental Protection, 79 Elm Street, Hartford, CT 06106; and Connecticut Siting Council, Ten Franklin Square, New Britain, Connecticut 06051. The Department granted the Office of the Attorney General (AG) and Environmental Northeast (ENE), 6 Beacon Street, Suite 415, Boston, Massachusetts, 02108 intervenor status in this proceeding.

On March 5, 2009, Santa Buckley Energy (Santa Buckley) of 154 Admiral Street, P.O. Box 1141, Bridgeport, CT 06601, requested and was granted Intervenor status. On March 10, 2009, Hess Corporation (Hess) of One Hess Plaza, Woodbridge, NJ 07095, requested and was granted intervenor status. The designation of intervenor status to both Santa Buckley and Hess was limited to their status as suppliers of natural gas and not as representatives of their respective customers.

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Similarly, on April 20, 2009, Bridgeport Energy LLC (Bridgeport Energy) of 10 Atlantic Street, Bridgeport, CT 06604 filed a motion requesting Party or a least an Intervenor status designation. The Department granted Bridgeport Energy Intervenor status. However, its participation is limited to issues related to the transportation agreement discuss in its motion request, transportation rates, and to the submission of briefs, reply briefs, and written exceptions.

E. PUBLIC COMMENT

1. Southern Customer Notice

In February 2009, Southern mailed a Notice pursuant to Conn. Gen. Stat. § 16-19a advising customers that the Company had filed an Application on January 20, 2009 to increase its rates. The Notice gave a brief explanation of the proposed increase and the causes that led to the proposal. The Notice also indicated that two evening public comment hearings would be held. The hearings were scheduled at the Bridgeport City Hall, on April 16, 2009 at 7:00 p.m. and in New Haven at the New Haven Hall of Records, April 22, 2009 at 7:00 p.m. to record public comment concerning the Company's Application.

2. Public Hearings

At the April 16, 2009 hearing in Bridgeport, no one from the public attended and the hearing was adjourned at 7:30. The second hearing was held on April 22, 2009 in New Haven and one consumer attended who spoke in opposition to the rate increase

3. Letters and Email Correspondence

The Department received 22 letters and emails regarding the Company's Application. While many were concerned with the state of the economy and its effect on homeowners and businesses, and customer's ability to pay bills, they were unanimous in their opposition to the proposed rate increase.

II. DEPARTMENT ANALYSIS

A. TEST YEAR/RATE YEAR

The Department establishes rates prospectively upon the basis of a historical test year, adjusted for pro forma purposes. In this case, the Company used the operating results for the 12-months ended June 30, 2008. The rate year for the traditional rate request is the 12 months ending June 30, 2010. Revenue Requirement Panel (RRP) PFT, p. 4.

B. RATE YEAR SALES FORECAST

1. Company Proposal

Southern claimed that customer usage patterns and customer-driven conservation efforts impact overall system throughput or sales and reduced the Company's ability to collect its fixed distribution costs. Although the normalized use per customer (NUPC) has recovered somewhat since 2006, the current 12-month normalized usage remains far below the level approved in the Company's last rate case. On a system-wide basis, the decline in NUPC resulted in 563 MMcf less firm normalized throughput in the test year compared with the level established in the Company's last rate case. Southern forecasts a continued NUPC decline through the rate year. Marks, Rudiak, Therrien PFT, pp. 24 and 25.

While the NUPC for Residential Heating Service (Rate RSH) declined since 2006, some rate classes, such as Residential Multi-Dwelling Service (Rate RMDS) and Large General Service (Rate LGS) experienced increases in their respective NUPC. These increases in NUPC occurred during a period of time when gas prices experienced both sharp decreases and then sharp increases. Response to Interrogatory GA-77 Supplement, Attachment B, pp. 3, 4, 9 and 10. The NUPC for Rate RMDS increased from 1,282.2 Mcf in December 2006 to 1,413.3 Mcf in March of 2009, reaching a high of 1,479.5 Mcf in October 2008. Id. For Rate LGS, the NUPC of 6,115.1 Mcf in December 2006 declined during the first half of 2007 to a low of 5,928.0 Mcf, rebounding by a steady incline to a high of 7,327 Mcf in November 2008. As of March 2009, the NUPC for Rate LGS was 6,868 Mcf, which remains significantly higher

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than the December 2006 level. Id.

NUPC and customer additions are independent. Customers are added to the system through conversions from other fuel sources and new premise additions. NUPC is driven by usage within existing gas using premise. NUPC may decline when prices increase and/or are sustained at a high level. A decline in NUPC may also occur as a result of more efficient energy use from structural conservation measures and equipment changes. Marks, Rudiak, Therrien PFT, p. 25. Over the past two years, Southern was successful in converting customers to natural gas due primarily to rising oil prices. The rising energy costs that drove customers to gas also caused existing customers to conserve, attributing to the decline in the NUPC. Firm customer growth in the test year partially offset lost margin from declining NUPC by $1.3 million. Id.

Despite a decline in NUPC to some rate classes, the Company's normalized firm sales have increased since 2006, with an average annual growth of 1,134,162 Mcf (778,896 Mcf in 2007 + 1,489,427 Mcf in 2008 / 2) over the 2-year period. Response to Interrogatory GA-62, Attachment C, p. 2. Total sales annual growth averaged 868,772 Mcf for the two-year period. These increases occurred despite several spikes in gas prices during this time period. Response to Interrogatory GA-77 Supplement, Attachments A and B.

The Company forecasted rate year sales by using a sophisticated sales use per customer (UPC) and customer econometric models. Residential econometric models were developed at the individual rate class level while commercial and industrial (C&I) rate classes were combined into one model. Marks, Rudiak and Therrien PFT, pp. 10-14. The results of the UPC models were multiplied by the applicable customer count model results to derive the rate year sales forecast before known adjustments. Id., p. 15.

Out-of-model known adjustments were added to the pro forma sales and customer forecasts to derive total rate year sales and customer counts. They recognize material changes in sales and customer counts that were not represented in the historical data series. Out-of-model adjustments consist of: 1) a negative adjustment for conservation programs for Rate RSH and Small General Service (Rate SGS) rate classes; 2) a positive adjustment for potential new distributed generation (DG) projects; 3) a positive adjustment for project 100/150 renewable energy initiatives and 4) a positive adjustment for interruptible customers switching to firm service. Also, due to a rate design change from Southern's previous rate case that assigns C&I sales customers to rate classes based on annual load (consistent with C&I FT customers), an out-of-model redistribution of existing load and customers among the C&I rate classes was made to test year data. Id., pp. 16-18.

The Company's out-of-model adjustment for conservation programs assumed an annual throughput reduction of 90,029 Mcf in its sales forecast. Id., p. 16.The calculation performed by the Company recognizes the cumulative conservation savings it expects during the second half of the pro forma year. Response to Interrogatory GA-225. Further, the proposed adjustment assumes the Company will achieve 100% of its projected expenditures, projects and resulting ccf reductions. Tr. 4/21/09, p. 1984. This is not always the case as the Company spent only half ($629,000 / $1,254,000) of its budget in 2007. Tr. 4/21/09, p. 1975.

Monthly customer and UPC econometric models used historical data for the 10-year period May 1998 through April 2008 to develop regression and time series forecasts. Sales data used in the development of the UPC models was first normalized for all firm rate classes. By eliminating the need to handle weather as an independent variable, the predictive importance of all other independent variables was enhanced greatly. Other independent variables consisted of the monthly average tariff cost of service and demographic data. A number of alternative models reflecting various independent variable choices were evaluated based upon a "goodness of fit" test. The tests, in part, withheld latest period information from the models while forecasting the missing periods. Marks, Rudiak, Therrien PFT, pp. 10-13; Schedule E-3.3a, pp. 1 and 2, Marks, Rudiak, Therrien PFT, Exhibit AEG-2, pp. 2 and 3. To measure customer growth, the economic model used exponential smooth-

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ing or Box-Jenkins time series analyses. According to Southern, the customer models are most heavily influenced by time, which is why the time series analysis, or lagged dependent variable regression model was used to forecast customers. Regression analysis was chosen to forecast UPC. Marks, Rudiak and Therrien PFT, pp. 10-14.

A price variable (total monthly rate class revenue divided by total monthly rate class sales) was developed and tested in all UPC models. Including a price variable required the Company to estimate the future cost of natural gas. It initially used the May 2008 New York Mercantile Exchange (NYMEX) natural gas futures settlement price strip to forecast gas cost through December 2009. Other independent variables tested include personal income, monthly and annual trends, price of competing fuels and monthly binary (dummy) variables. Multiple model profiles were conducted for each rate class. A model profile consists of a mixture of independent variable specification techniques and combinations, use of lag terms, and different data periods (monthly versus quarterly, etc.). Marks, Rudiak, Therrien PFT, Exhibit AEG-2, pp. 5-7. The acceptability of each model was based on a number of criteria. Marks, Rudiak, Therrien PFT, Exhibit AEG-2, p. 7.

During the proceeding, the Department requested that Southern develop new C&I UPC and customer models. The new models would breakout the combined C&I data into a separate model for commercial data and a separate model for industrial data. The individual C&I UPC models were very similar to the combined model filed in the Application in that they all used regression equations including a price variable. The commercial-only UPC model is identical in structure to the combined model filed in the Application. The industrial UPC model differs from the combined model only in that it does not include a 12-month lagged independent variable. The commercial-only customer model is identical to the combined model specifications. However, the Company employed a time series modeling approach for the industrial customer model because regression modeling was not successful. When comparing the separate C&I economic model results for the same time period as the Company's original combined forecast (April 2009), the separate C&I econometric models produced lower total C&I sales (8,314,472 Mcf) than what was produced by the combined model (8,615,083 Mcf). Southern stated that employing separate C&I models should provide better forecast accuracy and will be adopted by the Company for future forecasts. Responses to Interrogatories GA-263 and GA-263 Supplement, Attachment 1, p. 1; Late Filed Exhibit No. 101.

Southern's forecasting process adjusted the actual test year sales of 28,163,937 Mcf for normal weather, migrations and growth to arrive at the Company's originally proposed rate year sales forecast of 30,317,676 Mcf, an increase over test year of 2,153,739 Mcf. Of that, test year firm sales of 22,293,286 Mcf were similarly adjusted to arrive at the originally proposed firm sales forecast of 26,652,802 Mcf; an increase of 4,359,516 Mcf. Schedule E-3.4, p. 1. The original customer forecast, which is a subset of the sales forecast (rate class customer count x rate class NUPC = sales forecast) increased test year firm customers of 174,588 (2,095,057 bills / 12 months) by 2,243 for a total rate year firm customer count of 176,831 (2,121,975 bills / 12 months). The total test year customer count of 174,797 (2,097,561 bills / 12 months) was increased by 2,162 for a total rate year customer count of 176,959 (2,123,511 bills / 12 months).Id., p. 2.

The Company updated its econometric models, as requested by the Department, based on the sales forecast developed in Late Filed Exhibit No. 59 (Department Requested) and the other based on the sales forecast developed in Late Filed Exhibit No. 112 (Final Proposed Forecast). Both revised forecasts reflected corrections, latest historical data through March 2009, out-of-model adjustments, updated gas costs based on the NYMEX strip as of April 16, 2009, and separate C&I UPC and customer econometric models.

The difference between the two updates is that the Company's Final Proposed Forecast reflected a revised price variable used in the UPC econometric models and resulted in different forecast totals. The revised price variable included not only a gas component but also dis-

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tribution component. Late Filed Exhibit Nos. 59 and 112; Response to Interrogatory GA-2 Corrected. While the gas component is still forecasted using NYMEX assumptions, the distribution component reflects the Company's originally proposed revenue increase of $50.1 million, rather than its revised revenue increase of $34.2 million. Tr. 5/7/09, pp. 2312 and 2314. The Company believes that including both distribution and gas prices in the models' price variable better reflects customers' responses to total bill increases. Late Filed Exhibit Nos. 59 and 112; Response to Interrogatory GA-2 Corrected and Supplement No. 2.

The results of both revised sales forecasts increased the rate year UPCs and customer counts resulting in modest increases to the originally proposed sales forecast. Response to Interrogatory GA-2, Supplement No. 2, Attachment 2; Response to Interrogatory GA-2 Corrected, Schedule E-3.4 Revised. While both revised forecasts produced the same customer count, the Company's Final Proposed Forecast produced lower proposed sales than the sales produced by the Department Requested sales forecast. See, table below. Test year sales are normalized because proposed rate year sales are normalized.

Sales Forecast (Mcf)					
Rate Class	**Normalized Test Year[al]**	**Original Proposed[al]**	**Final Proposed[aal]**	**Department Requested[aaal]**	**DPUC Requested Increase/ (Decrease) from Test Year**
RSG	615,931	580,848	575,128	575,128	(40,803)
RSH	12,577,676	12,047,014	12,828,877	13,096,866	519,819
RMDS	771,506	753,713	865,190	871,670	100,164
SGS	2,839,415	1,439,430	1,642,380	1,687,492	(1,519,923)
GS	1,208,742	1,801,196	1,892,999	1,913,020	704,278
LGS	1,317,693	2,335,969	2,782,252	2,803,714	1,486,021
RMDS-FT	556,682	483,638	581,595	586,178	29,496
SGS-FT	206,697	178,606	192,141	195,430	(11,267)
GS-FT	651,494	585,740	632,848	644,430	7,064
LGS-FT	3,341,061	3,834,378	4,659,391	4,705,418	1,364,357
Total Firm	**24,086,897**	**24,040,532**	**26,652,802**	**27,079,347**	**2,992,450**
Special Contracts	1,429,162	2,344,051	2,344,051	2,344,051	914,889

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IS	4,382,843	3,930,222	3,456,465	3,456,465	(926,378)
NGV	3,125	2,871	2,871	2,871	(254)
Total Interrupt-ible	4,385,967	3,933,093	3,459,335	3,459,335	(926,632)
Total On-System	29,902,026	30,317,676	32,456,188	32,882,733	2,980,707
Other	55,522	0	0	0	(55,532)
Total Sales	**29,957,548**	**30,317,676**	**32,456,188**	**32,882,733**	**2,865,185**

a1. Sch. E-3.4, p. 2;

aa1. Response to Interrogatory GA-2 Corrected, Sch. E-3.4 Revised, p. 2

aaa1. Response to Interrogatory GA-2, Supplement 2, Attachment 2.

The table below compares the Company's original and final proposed customer count with test year figures.

Customer Count (Number of Bills / 12)				
Rate Class	**Test Year[a1]**	**Original Proposed[a1]**	**Final Proposed[aa1]**	**Final Proposed In-crease/(Decrease)**
RSG	26,358	25,323	24,627	(1,731)
RSH	129,540	133,706	132,994	3,454
RMDS	594	609	660	66
SGS	14,825	13,820	13,888	(937)
GS	1,069	2,140	2,145	1,076
LGS	261	471	484	223
RMDS-FT	571	324	370	(201)
SGS-FT	679	649	651	(28)
GS-FT	535	539	541	6

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LGS-FT	407	449	472	65
Total Firm	**174,588**	**177,946**	**176,831**	**2,243**
Special Contracts	1	3	3	2
IS	200	165	117	(83)
NGV	7	7	7	0)
Total Interruptible	207	172	124	(83)
Total On-System	174,796	178,121	176,958	2,162
Other	1	1	1	0
Total Customers	**174,797**	**178,122**	**176,959**	**2,162**

a1. Schedule E-3.4, p. 3

aa1. Response to Interrogatory GA-2 Corrected, Sch. E-3.4 Revised, p. 3.

The Department Requested sales forecast results in a revenue requirement of $32.3 million, a decrease of $1.9 million from the Company's final proposed revenue requirement of $34.2 million. Response to Interrogatory GA-2 Corrected and Supplement No. 2.

OCC believes that the Company's arguments for adopting their econometric-based sales forecast are misleading and that the predicted sales level should probably be increased. The Company's econometric model does an excellent job of predicting sales, as witnessed by the fact that forecasted sales resulting from the current econometric model are within 1% of models used in earlier cases. OCC argues that the precipitous decline in NUPC is due to the Company's use of NUPC in two different ways. NUPC refers to both the model's input (weather normalized usage per customer) and its output. According to OCC, the difficulty is that the model output reflects weather normalization plus the impact of price and time. In any event, sales should be increased because gas costs, a strong predictor of sales, is much lower today than it was when the case was filed. Lower gas prices translate into greater sales and revenues for the Company. Brief, pp. 166-171.

2. Discussion

a. Approved Sales Forecast

The Department believes that separating commercial from industrial customers in the UPC and customer models will result in more accurate forecasts. Therefore, the Department approves this approach and directs the Company to use this approach in future rate applications.

The Department rejects the two-part price variable model. The Company introduced a separate distribution price component too late in the evidentiary process to be properly evaluated. And the distribution price component used in the Final Proposed Forecast does not reflect the final proposed revenue requirement. Finally, given the structural complexity and dynamic behavior of the model, the Department has no practical way of conducting its own investigations and what-if adjustments to the models. As model sophistication expands, Departmental options contract to either full acceptance or rejection. If the Company submits similar model con-

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structions in future rate applications or supply and demand filings, it will need to provide the Department with a workable spreadsheet model.

The Department finds the Department Requested sales forecast developed in Late Filed Exhibit No. 59 and submitted in Response to Interrogatory GA-2 Supplement No. 2, reasonable and is approved with one caveat. The negative adjustment of 90,029 Mcf for conservation programs included in the approved forecast is not appropriate. The conservation adjustment mechanism (CAM) is the appropriate vehicle for recognizing lost margin recovery. Nonetheless, the Department will let this sales forecast stand by making the following, offsetting adjustments. The Department denies the proposed negative adjustment of -90,029 Mcf for conservation programs while also reducing the sales forecast by the same level to account for the denial of the new business rate base associated with the Yale Sterling DG project. See Section II.C.2.e., New Business.

The Department approved sales forecast changes the Company's Final Proposed Forecast. This will result in total revenues of $388,663,339, an increase of $4,261,093 from the Company's Final Proposed Forecast and a limited number of cascading changes to certain expense and rate base accounts. See, Response to Interrogatory GA-2, Supplement 2, Attachment 2, p. 35. Each of these changes, referred to as a sales forecast adjustment (SFA), is reflected in the respective sections below with other Department adjustments.

b. Weather Normalizing Sales

Concerning the weather normalization of test year sales for forecasting purposes, Southern used Bridgeport Sikorsky Airport (Sikorsky) heating degree day (HDD) data from the National Oceanic Atmospheric Administration (NOAA) report, published approximately every 10 years. The NOAA Report used in the instant case covers the 30-year period 1971 to 2000 (NOAA Report). Tr. 4/13/09, p. 657; Response to Interrogatory GA-75. The average annual HDD from the NOAA Report is 5,466. Late Filed Exhibit No. 53. The Company normalizes test year sales at the rate code level for each weather sensitive rate code. Response to Interrogatory GA-75.

During cross-examination, the Department asked whether the Company could use another source for determining normal weather that would have more recent weather data. The Company stated that it could use the NOAA numbers reported monthly to Sikorsky (Monthly NOAA Data), which is a similar method to what is used by its sister company, the Connecticut Natural Gas Corporation's (CNG). Tr. 4/13/09, pp. 657-658. The latest available Monthly NOAA Data is for the 30-year period 1978 to 2007. The average HDD for this period is 5,377, which is 89 HDDs warmer than the 30-year average from the NOAA Report used in the instant case. Late Filed Exhibit No. 53. The colder period in the NOAA Report increases forecasted sales, all else being equal, over the warmer period in the Monthly NOAA Data. Tr. 4/21/09, pp. 2004 and 2005.

Southern agreed that using more recent weather data would better reflect the latest weather patterns and result in a more accurate sales forecast. Tr. 4/21/09, pp. 2005-2008. When asked why Southern chose to use the older NOAA Report in developing its sales forecast for the Application, the Company stated that it did not know. Historically, that is what was used. Tr. 4/13/09., p. 659. The Department asked the Company if it could update the data in the instant proceeding for new weather normals based on more recent weather. The Company stated that it could. Tr. 4/13/09, pp. 657-659. However, when updating the sales forecasts at the end of the proceeding the Company continued use of the NOAA Report. Response to Interrogatory GA-2.

In its Written Exceptions, Southern argued that because the Department terminated the WNA (see, Section II.K.8. Weather Normalization Adjustment below), it must decrease the Company's sales forecast to recognize the most recent 30-year average normal degree days in the Monthly NOAA Data. This reduction to sales would result in lower pro forma revenue at present rates and would increase the revenue requirement by the same amount. Written Exceptions, pp. 97-99.

The Department disagrees with the Company's argu-

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ment that the Department must lower the sales forecast to reflect the warmer weather period in the Monthly NOAA Data. The Company had ample opportunity to use the Monthly NOAA Data that it now demands be used in the Company's sales forecasting process. First, the Department is perplexed as to why the Company would choose to use older data of any sort in its Application when more recent and relevant data was available. Second, even though the Company stated that it could update the weather information in the instant proceeding, and acknowledged that doing so would result in a more accurate forecast, when given the opportunity to do so in its sales forecast updates, it chose not to. Now that the higher sales forecast may disadvantage the Company in its pursuit of its requested rate increase, the Company wants the Department to adjust the sales forecast based on information the Company could have used. The Department denies the Company's request.

For better forecasting accuracy, the Department believes that the most current data available should be used when normalizing sales. In future rate case filings, the Company is directed to use the most recent available 30-year period of Monthly NOAA Data for normalizing sales.

C. RATE BASE

1. Pro Forma Plant Additions and Retirements

a. Account 378, Meter and Regulator Equipment General

Account 378, Meter and Regulator Equipment General, includes investment associated with measuring and regulating vaults along with associated equipment. Depreciation Study, pp. 4-13. Southern proposed $402,863 of capital additions and $480,244 of retirements related to this account. Southern is currently reviewing the assets included in this account to determine the level of additional retirements that are required to be recorded on the books and records for property no longer in service. Id. Netting the additions and retirements to Account 378 resulted in a pro forma adjustment of negative $77,381. The test year rate base as of June 30, 2008 was $8,242,748. Adding the negative adjustment above results in a proposed rate year rate base of $8,165,367. Schedules B-2.1 and 2.2. The Company did not provide specific testimony or documentation for the proposed rate year rate base of $8,242,748, showing the type, description and in-service dates of the individual assets and account entries. The Department investigated 277 account entries in detail.

The proposed capital additions to Account 378 are supposed to be district regulators and gate stations. Nineteen account entries were payroll and two were petty cash entries with an in-service date of July 1, 1973. Other items include painting gas vaults and an entry described as Company Auto. Response to Interrogatory GA-98, Attachment 2.

The Department's review indicated that 23 of the 277 retirements listed in the response to Interrogatory GA-98 appear to be expenses. Numerous expense entries have been in rate base since 1971. Since these expense entries have been included in rate base, the Company has improperly earned a rate of return on these expenses for 38 years. It is wrong for Southern to include expenses in rate base. The Department believes that Southern's accounting demands further investigation. The Department was unable to verify whether the remaining assets in the account are proper. See, Conn. Gen Stat. § 16-22. Therefore, the Department will assume that if 23 of the 277 items in this account are expenses then 8.3% of all assets in this account are expenses (23 / 277 = 8.3%). Therefore, the Department will disallow 8.3% of the $8,242,748 in rate year rate base in Account 378, or $684,416.

b. Account 390.1, Structures and Improvements

Investments under Account 390.1, Structures and Improvements, are related to the capital investment associated with general structures and improvements, such as buildings. Depreciation Study, pp. 4-27. Southern proposed $1,451,654 in capital additions related to improvements at the Company's facilities. The test year rate base of this account was $11,720,161 and the total rate year rate base was $13,170,815. Southern is retiring

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$1,000 of rate base related to security fencing at the main warehouse in Orange. Schedules B-2.1 and B-2.2; Response to Interrogatory GA-98, Attachment 2. Southern provided an itemization of the capital additions to Account 390.1. The exhibit lists nine capital additions expected to be included in the rate year rate base for Account 390.1 and one capital addition related to security fencing at the Orange Operations Center for $2,000. Response to Interrogatory GA-98, Attachment 1. Southern provided an update to its proposed capital investment for this account of $1,339,857. Response to Interrogatory GA-2, Attachment 2, Schedule B-2.2.

The Department accepts the proposed retirement of $1,000 for security fencing in Orange in Account 390.1. Other capital additions are discussed below.

i. HVAC System

Southern proposed HVAC additions of $653,995; one at the Control Center at the Milford liquified natural gas (LNG) facility and the other one at the Operations Center, 60 Marsh Hill Road, Orange. These projects were listed as three different line items: $307,613 related to heating ventilation air-conditioning (HVAC) at the Milford LNG facility, $196,382 for the HVAC's installation and an estimated cost of $150,000 for the control system at the Orange facility. Response to Interrogatory GA-98, Attachment 1.

The Company stated that its policy is to solicit a minimum of three requests for proposal (RFP) responses for all work that is expected to exceed $15,000. Southern only provided a single RFP response from Tucker Mechanical/Emcor Service (Tucker Mechanical) related to HVAC work at the Milford Control Center and the Orange Operations Center. Tr. 4/14/09, pp. 827-829. The Tucker Mechanical proposal and the final invoices received from the contractor did not separate out the cost of the air conditioning (AC) units, furnaces, and heat pumps. Id., pp. 835 and 836.

Southern proposed to include $307,613 in rate base Account 390.1, related to HVAC at the Milford LNG facility. The HVAC equipment included replacement of AC and heat units in the LNG control building. The HVAC system was a 1970's era system that was inefficient and had "employee issues." The Company did not test the HVAC system to determine unit efficiency prior to their proposed replacement. The Company's exhibit stated that Tucker Mechanical's rates were more competitive than other bidders. Id., pp. 828-832; Response to Interrogatory GA-436. The HVAC work at the Milford LNG facility Operations Center included removing the existing multi-zone roof top AC units and installing two 2.5 ton mini-split units in the facility's control building. The project also included installing three new gas fired furnaces and three new Robur gas fired heat pumps. The witness was unable to answer specific questions related to these items other than a heat pump provides "supplement heat" and is required by the contractor. The building did not have heat pumps prior to this project and Southern was unable to identify if the heat pump, mini split and furnaces were combined or individual units. Id., pp. 828 and 836.

As the temperature gets colder, the efficiency of the heat pump decreases. Therefore, supplemental heating sources must be added to the facility to produce heat during the coldest part of the winters. While Southern purchased new gas fired furnaces, AC units and heat pumps for this facility, it did not provide or indicate the efficiency gained by replacing the units. Southern indicated that it did not perform a cost/benefit analysis regarding operating and maintaining the old units versus purchasing new units. Tr. 4/14/09, pp. 828-844. Southern did not obtain 3 bids but relied on one contractor to determine the equipment for the project. The proposal did not separate the cost of the furnaces from the heat pump.

Southern recently purchased the facilities at 60 Marsh Hill Road, Orange, CT where the 12 HVAC units need to be replaced. The replacement of these units require 1-Trane 12.5 and 1-17.5 ton units along with a 1-Trane 20 ton roof top unit with associated duct work. The existing Carrier Parker control system would be removed and replaced with a Web DDC system. The total anticipated cost is $345,796, including $196,382 for the HVAC's installation and $150,000 for the control sys-

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tem. Response to Interrogatory GA-436; Tr. 4/14/09, pp. 838-841.

As stated above, Southern's issued RFPs for the HVAC projects and Tucker Mechanical was the only RFP response received. However, the agreement with Tucker Mechanical on page 15 states that Tucker Mechanical's "... rates are on file and were more competitive then other bidders."Response to Interrogatory GA-436.

The Department finds that Southern provided conflicting testimony regarding the RFPs and bidding process for the HVAC systems. The Department specifically requested the Company submit the "RFP responses" for these projects. However, the Company only submitted the copies of the Tucker Mechanical proposal, invoices and the agreement and did not indicate how many RFP were issued and received. Southern did not receive three HVAC RFPs as is its policy. Based on the aforementioned, the Department disallows the capital additions related to the proposed HVAC additions of $654,409 ($307,613 + $196,796 + $150,000) related to the Milford LNG facility's Control Center and Orange Operations Center.

ii. Emergency Generator

Southern proposed to include $150,000 capital addition in rate base related to the purchase of an emergency generator at the Orange Operations Center. This generator will be the second unit at the center. Southern testified that it lost power at the Operations Center twice during the last several years. Tr. 4/14/09, pp. 843-845. These emergency generators are in addition to the new DG unit that produces electricity. Tr. 4/14/09, pp. 844 and 845.

The Department believes that the purchase of the second emergency generator for the Orange Operation center is redundant and unnecessary. Further, the Company did not indicate during the hearings, why it needed a second emergency generator at the Operations Center. Therefore, the Department disallows the $150,000 capital addition to rate base for the purchase of a second emergency generator.

iii. Garage Lifts

The Company proposed an addition to the rate base of $165,846 for the replacement of the garage lifts at the Orange Operations Center at 60 Marsh Hill Road, Orange, CT. Response to Interrogatory GA-98 Attachment 1. Southern indicated that the garage lifts were to be replaced because of hydraulic leaks, but only one of the lifts had actually leaked hydraulic fluid. The Company claims that the units installed were more cost effective then the older lifts. Even though Southern proposed $165,846 to replace the lifts, it spent only $54,049. Therefore, Southern reduced Account 390.1, Structures and Improvements, from $165,846 to $54,049. Responses to Interrogatories GA-2 and GA-98 Attachment 1; Late Filed Exhibit No. 67; Tr. 4/14/09, pp. 852 and 853. Southern did not issue any RFPs for replacement of the garage lifts. Further, a RFP was not necessary because the vendor installing the garage lifts was an approved vendor for the installation of this type of lift. Late Filed Exhibit No. 67.

As stated earlier in this Decision, the Company policy regarding RFPs is that any expenditure greater than $15,000 must be issued for RFP responses. Southern did not comply with its purchasing policy, because it did not issue RFPs for the replacement of the garage lifts, which it estimated would cost $165,846. Due to the fact that the Company did not follow its own policy and obtain three bids, the Department disallows the entire capital expenditure of $54,049 from rate base.

iv. Pipe Yard Work and Workplace Construction

Southern proposed a rate base addition of $200,000 for work to the pipe yard. This cost reflects proposed capital addition for calendar 2009 related to installation of covered bins, installation of a concrete surface for new or existing material bins and adjacent work areas, new curbing, drainage, lighting and associated electrical work. This work would improve the pipe yard facilities and the process of delivering and removing excavation material. Response to Interrogatory GA-438.

Southern proposed a budget amount of $250,000 be in-

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cluded in rate base for workplace construction. This is to be spent on employee office and work space construction, along with departmental moves requiring walls and offices be built. The workplace construction included in the budget is unplanned and is expected to develop throughout the 2009 calendar year. Response to Interrogatory GA-438.

The Department believes that the addition of $450,000 related to the proposed pipe yard and workplace construction is unnecessary at this time based on the economic conditions. Southern must prioritize its capital expenditures into categories that are absolutely necessary and those not necessary and can be deferred. The Department disallows the proposed rate base additions of $200,000 for the pipe yard work and the $250,000 related to workplace construction.

v. Summary

Based on the above analysis, the Department will reduce the proposed capital additions to Account 390.1, Structures and Improvements, by $1,308,458 ($150,000 + $654,409 + $54,049 + $200,000 + $250,000). Therefore, the total allowed capital additions to Account 390.1 will be $31,399 ($1,339,857 - $1,308,458).

c. Account 391.1, Office Furniture

As of June 30, 2008, the current rate base in Account 391.1, Office Furniture, is $3,849,324. Southern did not propose to add any capital additions to the rate year for this account. Southern's Application included a proposed retirement of assets in the account of $2,129,735 through the midpoint of the rate year. Therefore, netting the proposed capital additions and retirements resulted in a rate year rate base of $1,719,589. Schedules B-2.1 and B-2.2. Account 391.1 is an amortization account with a proposed amortization rate of 5.84%. Tr. 4/14/09, p. 822; Depreciation Study, p. 2-2. The depreciation expense is $100,424 for this account. Schedule WPC-3.50.

During 2007, Southern retired $12,447,042 from rate base related to Account 391. Southern claimed that once the office furniture was fully amortized, those assets are retired. The Company performed a mass retirement during 2007 to clean up assets that were included in this account. Response to Interrogatory GA-149. The Company did not receive any gross salvage for any of the retirements from rate base related to this account. Retirements of these items in rate base are related to the book value of the items and not a physical retirement. It could not determine which of the proposed retirements resulted from a book retirement versus physical retirement and disposal of the asset. Southern was unable to identify if these assets were still in the Company's possession. Tr. 4/14/09, pp. 819-822.

Southern provided a list of retirements that it anticipates will occur through the midpoint of the rate year. The Company is retiring 431 items from rate base in Account 391.1, which were purchased between January 1, 1993 and January 1, 1995. General types of office furniture included in the retirements include shelving units, file cabinets, furniture and associated repairs, conference room tables, doors and door repairs, furniture related to the Company's move from Bridgeport to Orange, tables, televisions, kitchen appliances, and copiers. Other items included were paintings, china, plants and planters, desk accessories, phone system (labor), Dell lap top computers freight charges, sales tax, relocation costs, and chain fencing. Also included was a transfer to construction work in progress (CWIP), which was not further defined. Examples of these retirements include 17 paintings valued at a total of $12,254 and $1,858,423 for furniture related to the move from Bridgeport to Orange. Response to Interrogatory GA-98 Attachment 2. Under the Company's current capitalization policy, many of these items would not be included in rate base. Tr. 4/14/09, pp. 824 and 825.

The Department's review indicates that a significant number of retired assets should never have been included in rate base. The Company agrees. Tr. 4/14/09, pp. 824 and 825. These items are being retired from the Company's books and ratepayers will not be paying for these assets in the future. However, the Company does not indicate whether these assets remain in-service or whether they have been disposed. The Department is concerned that Southern cannot verify whether any of

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these retired assets, including the paintings, remain in the Company's possession. The Company was unable to provide documentation regarding specific items remaining in rate base. The Department is unable to verify whether the remaining assets included in the rate year rate base of $1,719,589 are properly included in this account. The list of retirements shows account entries in rate base that should have been expensed. Based on this fact, it is reasonable to assume that additional account entries included in rate base would have the same issue. The Department will audit the items in this account to determine whether any items should be moved to other accounts and any account entries relating to expense items should be removed.

Southern shows retirements of chain link fencing from Account 391.1, Office Furniture, while it also shows retirements of fencing in Account 390.1, Structures and Improvements. The inclusion of chain link fencing in Account 391.1 does not corresponded to the Uniform System of Accounts. This asset should have been in rate base under Account 390.1, Structures and Improvements. The Department believes retirements of assets from Account 391.1, described above, indicates that Southern has serious deficiencies in its application of the Uniform System of Accounts. Because Southern demonstrated that Account 391.1 contains items properly recorded in Account 390.1, the Department will apply the depreciation rate associated with Account 390.1, Structures and Improvements, of 1.44% to all assets included in Account 391.1, Office Furniture. Therefore, the resulting depreciation expense associated with Account 391.1 is calculated by multiplying the rate year rate base of $1,719,589 by 1.44% ($24,762). As a result, the Department will disallow $75,662 ($100,424 - $24,762) of the proposed depreciation expense from Account 391.1. The Department notes that the inclusion of expense related entries in the list of retirements for Account 391.1 is an indication of accounting deficiencies discovered in other plant accounts discussed in this Decision.

d. Account 391.2, Electronic Data Processing Equipment

Southern proposed $734,071 of capital additions and $908,321 of retirements to Account 391.2, Electronic Data Processing Equipment. The Application showed a test year rate base of $1,136,016 and a corresponding rate year rate base of $961,766. Schedules B-2.1 and B-2.2. Under Account 391.2, the Company proposed to retire Asset No. 52067895 with an in-service date of July 1, 2003, described as EEMC SAP Back Office License Fee (License Fee) for $200,000. The exhibit also lists a Reclass of Asset No. 52067897 for an amount of $200,000 dated January 2003, which also has an in-service date of July 1, 2003. The reclass also includes a February 2003 Asset for an amount of $9,993 with an in-service date of July 1, 2003. Response to Interrogatory GA-98, Attachment 2.

The Department reviewed the items listed in the proposed retirements and discovered a License Fee dated July 1, 2003 of $200,000 for its affiliate EEMC's software license. Additionally, the exhibit shows a reclassification of a $200,000 asset dated January 1, 2003. While this appears to be related to the License Fee, the date of the reclass occurred six months before the License Fee and the asset number of the reclass is different than the asset number of the License Fee. As a result, the reclass must be related to another asset in rate base. However, it is unclear to what the reclassification is related. The Company did not provide any documentation to support the reclass. The reclass asset number includes a reclassification of a capital investment of $9,993, which is not included in the retirements. The reclassification of the assets occurred five months prior to the addition of EEMC's software license in rate base.

The Department calculated that 17.6% of the test year rate base was attributed to the EEMC License Fee by dividing the $200,000 fee by the total test year rate base of $1,136,016 for Account 391.2. Since Southern did not provide a complete list of assets for this account, the Department will assume that 17.6% of assets included in the test year is applicable to the remaining assets in the rate year rate base. The Department applied the 17.6% to the $961,766 rate year rate base. This results in a disallowance of $169,270 ($961,766 * 17.6%) from this account related to affiliate expense items. There-

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fore, the Department allows $792,496 ($961,766 - $169,270) as the rate year rate base for Account 391.2.

As discussed earlier in this Decision, EEMC performs numerous administrative and operating functions and services, including information technology, purchasing, accounting and payroll for all of the Energy East Corporation (Energy East) operating utilities. Based on the Company's capitalization policy that was in effect during 2002 and 2003, Southern should not have included any cost in any rate base account related to its affiliate. Further, including any item in rate base related to an affiliate of Southern is unacceptable and highly improper. However, since this License Fee is being retired, ratepayers will no longer be paying for this account entry in the rate year. But this item was included in this itemization account and has been recovered though rates over the last five years. As a result of the discovery of the affiliate's License Fee in rate base and other issues, all property records included in this account will be audited to determine the validity and prudency of each item.

e. Accounts 392 and 396

The Uniform System of Accounts, Account 392, Transportation Equipment, includes the costs related to transportation vehicles such as automobiles, trucks and other transportation vehicles used for utility purposes. Southern proposed capital additions to rate base of $2,814,239 associated with this account. Southern expects to retire $3,057,075 of rate base items in this account as of December 31, 2009. Southern included a pro forma adjustment of negative $242,836 for new equipment based on netting the additions and retirements to this account. The total pro forma adjustment of negative $242,836 was added to the test year rate base of $9,529,857 for a total rate year rate base of $9,287,021. Schedule B-2.2.

Southern proposed to include transportation vehicles such as new cars and trucks, service vans; and construction vehicles such as backhoes, loaders, dump trucks, trenchers and flatbed trailers in Account 392. Construction vehicles were included in this account because they were registered with the Department of Motor Vehicles and are legally capable of being driven on the public roads. Southern separated the items included in Account 392 in to three sub-categories Account 392, Service Vans, Account 392.1, Light and Heavy Trucks and Account 392.2, Passenger Cars and Trailers. Tr. 5/7/09, pp. 2264-2285; Depreciation Study, pp. 4-30 - 4-32.

Under the Uniform System of Accounts, Account 396, Power Operated Equipment, includes motorized equipment used in the construction process. The total test year rate base for Account 396 was $599,239. The Company did not propose any additions to this account in its Application. It did list a pro forma adjustment of negative $251,774 related to retirement of assets under this account. It included a rate year rate base of $347,465 ($599,239 - $251,774). Schedules B-2.1 and B-2.2. Southern made an adjustment to Account 396 to account for the assets it transferred from Account 392. Tr. 5/7/09, pp. 2271 and 2272. In Southern's Written Exceptions at page 56, the Company admits it misclassified plant accounts. The response to Interrogatory GA-2 lists a test year rate base for Account 396 of $599,239 and a pro forma adjustment of $756,242. This results in a proposed rate year rate base of $1,355,481 ($756,242 + $599,239). Response to Interrogatory GA-2; Schedule B-2.1, p. 7.

i. Capital Additions and Retirements

The primary types of vehicles included in Account 392 under Southern's proposed rate case application are those used for transportation purposes including service work, trucks and automobiles. Southern proposed to retire 82 of the vehicles described above worth $2,363,427 by the midpoint of the rate year. Southern proposed to purchase another 82 items described as vehicles under this account that are specifically related to transportation, including trucks, service vans and other transportation related equipment equal to $939,422. Late Filed Exhibit No. 69, Attachment 1; Schedules B-2.1 and B-2.2.

In Late Filed Exhibit No. 69, Southern included 39 items in Account 392, which were divided into multiple types of vehicles. The exhibit shows that 14 items were

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described as 2008 Ford-4x4-4 or 4x2-4 DR Ext Cab-Ranger with a range of prices between $543 and $1,833. The majority of these Rangers have a price range between $908 and $1,476. Five items described as 2008 Ford-4-Door Sedan Focus were included in the Company's response to Interrogatory GA-98, Attachment 1, with a purchase price of $812 for each vehicle. The above cited response also included 2 items described as 2008 Ford-4x2-4 - General Service and 17 items as 2008 GMC - Full Size 4x2-1 ton Van. All 19 of these vehicles were listed with a respective purchase price of $1,165. The same exhibit shows that 16 additional items described as 2008-GMC-Full Size 4x2-1 Ton Van with a purchase cost of $23,312 for each vehicle.

The second type of vehicles included Account 392 were 42 vehicles related to construction activities for a total capital addition of $1,874,817. The vehicles related to construction activity included 2 forktrucks, 1 Advance Sweeper, 14 flatbed trailers, 6 backhoes and extend backhoes, 2 loaders, 9 trucks with related equipment used in construction activities and 1 trencher. Late Filed Exhibit No. 69, Attachment 1. Southern made an adjustment and removed 21 account entries from Account 392 that were related to construction activity and moved those items to Account 396. The Company removed $1,090,733 from Account 392, Transportation Equipment, and added that same amount to Account 396, Power Operated Equipment. Late Filed Exhibit No. 69, Attachment 1.

Southern proposed to retire a total of 119 vehicles from Account 392 valued at $3,057,075 by the midpoint of the rate year. Southern's exhibit did not provide any data regarding anticipated gross salvage for the 119 vehicles retirements included in that account. Schedule B-2.1 nets the capital additions and retirements described above and did not include any actual gross or net salvage. As of March 31, 2009, 113 of the 119 vehicles included in Account 392 were sold. Of the 113 vehicles, 32 were related to construction activities and included four forklifts and nine items described as flatbed trailers; dump trucks, welders, utility trucks and crew trucks. Southern intends to retire $1,151,050 worth of vehicles specifically related to construction activities. Late Filed Exhibit No. 69.

ii. Depreciation

Southern's depreciation expert witness, Mr. Robinson, testified that he did not review the data related to the vehicles and equipment contained in Account 392. He indicated that the Company typically would not submit specific descriptions related to individual account entries to the depreciation consultant as part of the Depreciation Study. Mr. Robinson submitted testimony and documents that indicated the typical life expectancy of construction equipment was between 12 to 15 years. Even though Mr. Robinson did not review the documents, it was his belief that construction equipment had been historically included in Account 392. The witness indicated that the Company should have in its records the detailed information regarding each item included in rate base under Account 392. However, the Company stated that providing a complete list of items contained in Account 392 and 396 would be an extremely burdensome task and, therefore, did not provide the complete list. Southern maintains its accounting records based on group accounting. It uses industrial age standards to determine whether transportation equipment should be retired. Tr. 5/07/09, pp. 2264 and 2285; Depreciation Study pp. 4-33. The Company's Depreciation Study shows that no assets were added to Account 396 since 2001. Prior to that year, the Company retired equipment from Account 396 during three of the seven years between 1993 and 2000. Depreciation Study, pp. 7-53 and 7-54.

Southern provided data regarding Account 392 that shows service vans with a proposed depreciation rate of 8.03% and an average service life of 12 years. The average remaining life for equipment in this account was 7.0 years. The Depreciation Study proposed a 20% future net salvage value for all service vans included in Account 392. Account 392.1, Light and Heavy Trucks, shows a proposed depreciation rate of 7.15% with an average service life equal to 11 years. The average remaining life for equipment in this account was 8.7 years. The Depreciation Study proposed a 15% future net salvage value for all service vans included in Ac-

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count 392. Account 392.2, Passenger Cars and Trailers, shows a proposed depreciation rate of 26.45% with an average service life equal to 6 years. The average remaining life for equipment in this account was 2.9% years. The Depreciation Study proposed a 15% future net salvage value for all service vans included in Account 392. Depreciation Study, pp. 4-30-4-32.

Examples of Account 396, Power Operated Equipment, include construction equipment such as excavation, backfilling, and trenching equipment. The proposed depreciation rate for this account is 26.10% with an average service life of 13 years and an average remaining life of 2 years. Southern's exhibit shows a proposed future net salvage of 10% for all power operated equipment included in this account. The current depreciation rate for Account 396 is 6.87% with a 10% future net salvage. The proposed depreciation expense for this account is found in Schedule C-3.23 and equals to $59,310.

Based on the response to Interrogatory GA-2, revised Schedule C-3.23 shows an increase in the rate year depreciation expense from $59,310 to $231,372. The increase was a result of the Company transferring 21 items from Account 392 to Account 396 as a result of discussions during the hearing in both this proceeding and CNG's proceeding. The transfer was based on Southern's interpretation of which items to include in these accounts under the Uniform System of Accounts. The Company proposed a rate base adjustment of $1,250,852 for Account 392 to account for the transferring of account entries to Account 396. Therefore, the total proposed rate base for Account 392 is $8,279,005 ($9,529,857 - $1,250,852). Response to Interrogatory GA-2; Tr. 5/07/09, pp. 2264-2285; Depreciation Study pp. 4-33; Schedule WPC-3.50; Schedule C-3.23.

iii. Discussion

The Department reviewed the Company's exhibits and testimony provided in the instant proceeding regarding Accounts 392 and 396. A review of the capital additions included in Late Filed Exhibit No. 69 shows that Southern transferred one half of the 42 construction vehicles from Account 392 to 396. As a result, 21 construction vehicles remained in the proposed capital additions under Account 392, with an original purchase cost of $714,348. After reviewing the list of capital additions included in Late Filed Exhibit No. 69, Attachment 1, the Department believes that 17 items, all described as 2008 GMC Full Size 4x2-1 Ton Van with a cost of $1,165, directly correspond to the other 17 items with the same description with a cost of $23,312. The 17 items stated above with a cost of $1,165 appear to be some type of attachment to the 1-Ton Vans.

The Department believes that the items included in Account 392 described as Ford Sedans and Rangers are not vehicles and should not be included in this account because the prices of the account entries are between $504 and $1,833 and too low to be vehicle costs. See, Late Filed Exhibit No. 69 Attachment 1. The list of capital additions did not include any reasonable prices for Ford Sedans or Rangers. It appears that these account entries are expense related items and should be expensed and not included in rate base. The Department added the dollar amounts associated with the 19 Ford Sedan Focuses and Ford Rangers described in Section II.C.1.e.i. Capital Additions and Retirements for a total of $45,117. Therefore, the Department disallows $45,117 in rate base associated with the Ford Sedans and Rangers that appear to be mislabeled as such.

Since historical data was not provided regarding the individual account entries included in the current rate base under Accounts 392 and 396, the Department is unable to verify whether the individual entries included in proposed rate year rate base correspond to the Uniform System of Accounts. The Department believes the retirements of construction related vehicles from Account 392 are an indication of accounting deficiencies in rate base accounts, similar to the other plant accounts discussed in this Decision. The Company included construction vehicles in the retirements from Account 392 and that these vehicles were historically included in this account. The Department believes that these retirements are representative of all assets included in rate base under Account 392. Therefore, it is reasonable to assume that the remaining assets in rate base are also comingled

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with assets that belong in other accounts along with improperly included expense items.

The Company's transfer of one half of the construction vehicles from Account 392 to 396 without the other construction vehicles complicates any attempt to correctly apply the depreciation rate to the accounts. Therefore, the Department will not accept the Company's proposed adjustment and transfer of the $1,090,733 from Account 392 to 396. The Department believes that Southern is retiring assets under Account 392 based on the age of the equipment. The Department cannot verify whether the items retired under Account 392 are valid. Southern's general fleet policy regarding retiring assets because of their age is inadequate. The Company did not compare the costs associated with maintaining the equipment versus the cost associated with purchasing new equipment. It appears that Southern is unnecessarily increasing rate base by purchasing assets that are unnecessary. The Department believes that age is only one factor that should be taken into account when an item in rate base is retired. Retiring assets to take advantage of accelerated depreciation or because of the asset's age is usually not cost effective. The correct analysis that Southern should perform is a comparison of the cost associated with maintaining a specific piece of equipment versus the costs associated with purchasing new equipment. Since the Company did not compare the costs of maintaining current equipment assets to the costs associated with purchasing new assets, it is unclear which assets should be retired or retained in the Company's fleet.

Based on the above, the Department is left with two divergent and opposing positions regarding the capital additions and retirements of assets included in Account 392. The Department could either approve or deny all of the capital additions. The Department believes that it was proper for at least some of the assets to have been retired. Other items should not have been retired. As a compromise, the Department will assume that 50% of the capital additions are appropriate and included in the rate year rate base. As a result, the total capital additions allowed during the rate year will be $1,407,111 ($2,814,239 *50%). The Department believes the 50% reduction to the rate year rate base sufficiently accounts for any disallowance properly related to the Ford Sedan and Rangers stated above. Therefore, the Department disallows $1,407,111 ($2,814,239 - $1,407,111) in rate base included in the rate year associated with Account 392.

The Department will apply the 6.87% depreciation rate from Account 396 to all assets included in Account 392. This will ensure that all construction related equipment included in Account 392 is not over depreciated. Applying the current depreciation rate for Account 396 to Account 392 prior to the transfer of assets is a simple methodology. As a result, the appropriate rate year depreciation expense is determined by subtracting the adjusted capital additions of $1,407,111 from the rate year rate base of $9,287,021 times the approved rate year depreciation rate of 6.87%, which results in a depreciation expense of $538,825 [($9,287,021 - $1,407,111 - $45,117) * 6.87%]. In summary, the Department disallows a depreciation expense of $295,149 ($833,974 - $538,825) and allows a rate year rate base of $7,834,793 ($9,287,021 - $1,407,111 - $45,117).

The Department reviewed the depreciation rates associated with Account 396. The Department believes the proposed depreciation rate of 26.10% for Account 396 is significantly overstated. Since the Company has been including construction vehicles in Account 392 and not in Account 396, the Company has skewed the average service lives, thereby, skewing the depreciation rate for this account. Since the Company must take responsibility for its accounting practices, the Department finds the proposed depreciation rate invalid. Therefore, the Department will apply the existing depreciation rate of 6.87% to the proposed rate year rate base of $347,465, which equals $23,871 ($347,465 x 6.87%). As a result the Department disallows $55,249 ($90,688 - $23,871) related to the depreciation expense from the Company's original rate case filing.

f. Account 397, Communication Equipment

For Account 397, Communication Equipment, the rate base as of June 30, 2008 was $1,662,545. Southern pro-

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posed a capital addition of $180,000 and an adjustment for the retirement of assets of negative $791,496. This results in a proposed total rate year rate base of $1,051,049 for Account 397. Schedules B-2.1 and 2.2; Response to Interrogatory GA-98, Attachment 1 and 2.

Regarding the $180,000 capital addition, Southern was unable to answer specific questions or provide the invoices for its expenditure of $105,000 related to security equipment installed at the Orange Operations Center and the $75,000 associated with security cameras for the gate stations shown in Late Filed Exhibit No. 67. The response only included invoices for the purchase and installation of the garage lifts at the Orange Operations Center. Tr. 4/14/09, pp. 854-857; Late Filed Exhibit No. 67.

Southern stated in its Written Exceptions that it did not include the invoices related to the security equipment discussed above because it did not purchase the equipment as of the date of the hearing on April 14, 2009. Written Exceptions, p. 56. However, the Company failed to indicate that it testified at the April 14, 2009 hearing that the security equipment was purchased and installed during 2008. Tr. 4/14/09, pp. 854-857.

The Department reviewed the testimony and documents provided to the Department by the Company regarding the capital additions to Account 397. Even though the Company was requested to include the invoices for the security equipment in Late Filed Exhibit No. 67, the Company did not. Consequently, the Department was unable to determine whether the items were actually purchased. Therefore, the Department disallows the proposed capital addition of $180,000 and allows a rate year rate base of $871,049 ($1,051,049 - $180,000) to Account 397, Communication Equipment.

g. Audit of Rate Base Accounts

The Department found that the evidence and exhibits submitted by Southern in this proceeding revealed numerous assets were included in the wrong Uniform System of Account's, accounts. Further, numerous accounts included expense related items that were retired from rate base accounts. The accounting and depreciation related issues that arose from the inclusion of assets and expenses related items in wrong accounts need to be corrected. The Department will direct the Company to perform an audit on all rate base accounts and file a report with the Department. The intent of the audit is to identify and make adjustments to the rate base accounts to ensure that assets are classified and depreciated correctly. Southern will identify all expense related assets included in each account. Southern will audit each of the rate base accounting records to determine which assets and associated dollars should be moved to other accounts or removed from rate base accounts. Southern will use the Uniform System of Accounts manual to determine the appropriate assets to be included in each account. The report will identify and quantify all items in each account that would not be allowed under the Company's current capitalization policy. The report will include dates of in-service, dollar amount and description of items. Finally, the report will indicate and identify all of the assets included in the rate base accounts and whether the assets are currently in-service or physically retired and included in the accounts rate base. Further, the Department's intent of this or any related expenses associated with this or related audits be borne by the shareholder.

2. Operations and Capital Expenditures

a. District Regulators and Gate Station Capital Expenditures

Southern proposed an annual expenditure of $421,000 for the rate year related to district regulators and gate stations. Southern typically replaces two regulator stations under this program a year and it is unusual to replace an entire gate station. The annual expenditures associated with district regulators and gate stations changes annually depending on the work the Company performs on these assets. Reis, Dobos, Malone and McNally PFT, p. 5.

Southern provided a list of major district regulator and gate stations projects for the last 10 years. Along with the list was a total year expenditure which ranges from

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a low amount of $48,000 to a high of $398,000. The $48,000 was for a system uprate at one of its locations and the $398,000 for five system uprates and a system tie-in at six different locations. Between 1999 and 2008, Southern reported a total expenditure of $2,305,000, which includes the lowest capital expenditure during the last 10 years of $169,000 in 1999. Response to Interrogatory OCC-186.

The Department finds that the proposed revenue requirement for the rate year includes expenditures for work to be performed at district regulator stations. The Department believes that using $169,000 for these types of expenditures is reasonable because of the current economic conditions. Further, the lowest capital expenditure for the last 10 years corresponds to the last economic down turn. As a result the total annual expenditures associated with regulators and gate stations will be set at $169,000. The Department disallows a total of $252,000 ($421,000 - $169,000) from the proposed rate case capital expenditures.

b. Meter Relocation Program

Southern requested to continue its current Meter Relocation Program, which is designed to relocate meters that are located inside of existing buildings to the outside. With the relocation of the meter, the Company also performs a service renewal from the bare steel mains in the street to the new meter installation. The Meter Relocation program is an essential part of its plan to reduce delinquent accounts receivable. The Company proposed to include annual capital expenditures of $2 million for the Meter Relocation program. Reis, Dobos, Malone and McNally PFT, pp. 5-8. Southern anticipates that it will move approximately 750 meters and 300 services under this program during calendar year 2009. Response to Interrogatory GA-366. Approximately 95% of the $2 million in capital expenditures is related to labor, permit fees, police, traffic and paving. The remaining 5% is related to material, piping, valves and fitting costs. Response to Interrogatory OCC-178; Tr. 4/14/09, pp. 758-795.

Southern testified that a significant number of inside meters have bare steel services, which are bare steel pipes without corrosion protection. These are typically in inner city neighborhoods with most in residential multifamily dwellings. There are approximately 35,576 bare steel services in the Company's service area. Southern was unable to specifically determine which dwellings had inside meters and bare steel services. Under its Bare Steel Replacement Program and Meter Relocation Program, the Company replaced a total of 1,400 services during 2008. The Company replaced 1,100 (1,400-300) bare steel services under the Bare Steel Replacement Program. Response to Interrogatory OCC-178 and Tr. 4/14/09, pp. 760-762.

The Meter Relocation Program moved 4,500 inside meters and renewed 2,059 bare steel services during the three-year period 2006 to 2008. During this period, Southern spent $9.3 million dollars in capital and was able to shut-off service to 2,600 delinquent accounts. During calendar year 2008, 90% of the 1,400 services renewed under the Bare Steel and Meter Relocation programs' were bare steel. Southern developed an estimated savings that resulted from the Meter Relocation Program by assuming that once the meters were relocated outside, the customer would be incented to pay delinquent balances that average $2,200 per customer account. Southern estimated its savings as equal to $5.7 million a year. The threat of termination changed customer behavior regarding delinquent balances. Tr. 4/14/09, pp. 758-795. The average cost of a service renewal is $4,150. The average multi-family dwelling has 2.5 meters and the average cost to move these meters is $887. Late Filed Exhibit No. 63.

During 2007, Southern shut-off 11,851 customers due to non-payment of bills representing $25 million. During 2008, Southern's target was to shut-off approximately 13,000 customers due to non-payment of bills. Southern provided an exhibit that showed $40,040,286 in outstanding receivables 120 days over-due. Southern did not provide the total number of customer accounts it used to calculate the $40,040,286 outstanding balance. Schedule F-6.0; OCC-33 Attachment 3, pp. 1 and 2.

OCC stated that the Meter Relocation Program expenditures for 2007 and 2008 included four compon-

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ents: Service Renewals, meters moved, Buffalo Gauge Valve installations and Curb Valve installations. OCC recommended that only a portion of the proposed $2 million capital expenditure be allowed in the rate year. OCC estimates that 75% of the proposed Meter Relocation Program's capital expenditures should be applied to the Bare Steel Replacement Program, since these costs are directly related to renewal of the service. The remaining $500,000 is appropriate for the Meter Relocation Program. Brief, pp. 81 and 82.

The Department estimates that it will take 50 years for Southern to complete the Bare Steel Service Replacement Program under current funding. The addition of the Meter Relocation Program, at best, could move an additional 300 services during the rate year with capital costs of $2 million. Therefore, continues to be reasonable to assume that it will take 50 years to move all 53,504 inside meters outside.

Public Act 09-31, An Act Concerning Utility Service Termination (Public Act 09-31) is effective on July 1, 2009. The Public Act states:
. . . the owner, agent, lessor or manager of a residential dwelling shall be responsible for providing a public service company . . . access to its meter or other facilities located on the premises of the residential dwelling promptly upon written request of the public service company . . .

As discussed in Section II.C.2.g. Automatic Meter Reading Program, Southern was able to access almost 100% of the inside meters to install AMR devices. Therefore, it is reasonable to assume that the Company should have the same accessibility to inside meters to either install remote shut-off devices or shut-off service when an account is delinquent. Public Act 09-31 enhances the Company's ability to gain access to shut-off delinquent accounts. The Company can make a landlord responsible for their tenant's delinquent gas bill if the landlord denies access to inside meters for shut-off. Public Act 09-31 reduces the need to relocate meters outside for credit and collection issues. As a result, the Department terminates the Meter Relocation Program. The proposed $2 million capital expenditure related to this program is disallowed. However, there is a corresponding $2 million in rate base associated with the Meter Relocation Program. The Department is transferring $1.5 million in capital expenditures from the Meter Relocation Program to the Cast Iron/Bare Steel Planned Replacement Program as discussed in that section. See, Section II.O.1. Based on the adjustment described above, the difference in rate base of $500,000 ($2 million -$1.5 million) remains. Therefore, to ensure the total capital expenditures allowed in this Decision are equal to the rate base, the Department will disallow the remaining $500,000 in rate base that was not transferred to the Bare Steel Replacement Program. The Department directs Southern to immediately make use of Public Act 09-31 to reduce uncollectibles and begin contacting landlords, managers, agents and lessors where access is being denied.

In the Company's next rate case, the Department will review the prudency of Southern's collection efforts related to inside meter access issues including any carrying costs for accounts with inside meters or any other relevant charges or costs. The Company will be directed to file an annual report in a working excel spreadsheet related to inside meters that includes the following items.
- list all inside accounts grouped by street address showing the highest account's arrearage first;
- number of customers at the address;
- total arrearage as of December 31;
- total number of days bills were delinquent;
- last time meter was tested;
- date Company shut-off gas service; and
- any other relevant information.

For those customers for whom Southern must terminate service resulting from a collection issue, the Company will apply a Disconnection Charge as described in the tariffs. If the customer should request service at a later time, the tariff required Reconnection Charge will be applied to that customer's bill.

c. Meter Services, Regulators and Installations

Southern proposed to include $2,286,000 in the rate year for capital expenditures related to meter services,

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regulators and installations, which included meter and regulator purchase and installation costs. Reis, Dobos, Malone and McNally PFT, pp. 5 and 10. The meters purchased under this category are used for new customers along with the Company's Meter Replacement Program. The Company did not provide historical evidence related to actual capital expenditures for this category. Reis, Dobos, Malone and McNally, PFT, p. 10.

OCC argued that Southern's proposed capital expenditures related to meter service, regulators, and installations ignored the current economic recession. OCC believes the proposed capital expenditure related to new main and service installations should be reduced by 40%. OCC applied its proposed 40% reduction to the relevant components resulting in a $400,000 reduction in the capital expenditures. As a result, the Company's proposed capital expenditures associated with this category should be reduced from $2,128,460 to $1,657,916. Brief, pp. 80 and 81.

The Department reviewed the table included in the OCC's brief and compared it to Southern's response to Interrogatory OCC-187, Attachment1. The data included on page 80 of OCC's brief related to Southern's proposal should be based on the proposed capital expenditures of $2,286,000 and not $2,128,460. The Department's analysis included in Section II.C.2.e. New Business reduced the Company's proposed capital expenditures for the rate year related to Normal New Business by 40%. New business is directly related to meter and regulator installations via the addition of new service installations that require a new meter. Therefore, it is appropriate for the Department to carry the 40% reduction over to meter service, regulators and installations specifically related to the New Business portion of this category of capital expenditures. Therefore, the Department will disallow $914,400 ($2,286,000 * 40%) in capital expenditures related to Meter Service Regulators and Installations. As a result, the Department will allow a total capital expenditure for this category of $1,371,600 ($2,286,000 - $914,400).

d. Land Structures Capital Expenditures

Southern testified that the Land Structures and Improvements - General category includes expected annual expenditures related to building improvements and repairs of the Company's facilities, such as security upgrades and purchases of furniture. Southern proposed to include $930,000 for capital expenditures under this category to be included in the rate year as itemized below.

Upgrades and Improvements	Costs	In Service Date
Replacement of obsolete HVAC Control system at the Orange Operations Center	$150,000	9/31/09
Replacement of an aging emergency generator at the Orange Operations Center	$150,000	9/31/09
Construction work and Paving associated with the pipe yard at the Orange Operation Center.	$200,000	12/31/09
Replacement of Security Equipment at Gate Stations (e.g., cameras, recorders, lighting)	$30,000	12/31/09
Security Equipment upgrades and additions (e.g., cameras, emergency	$150,000	12/31/09

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phones)		
Workplace office type construction as needed	$250,000	12/31/09

The Department reviewed the above list of items included under this capital expenditure category. As stated, in Section II.C.1.b. Account 390.1, Structures and Improvements, the Department disallowed the capital expenditures associated with the HVAC control system at the Orange Operations Center of $150,000, the purchase of a second emergency generator for $150,000, the construction work associated with the Pipe Yard of $200,000 and the workplace office construction of $250,000. These items totaling $750,000 are already included in the derivation of the Land, Structures, and Improvements- General capital expenditures of $930,000, which are itemized in the response to Interrogatory OCC-191. The HVAC work, Pipe Yard construction, replacement of the emergency generator and the workplace construction are one time projects that are being included in revenue requirements as if they are multi-year projects. The inclusion of these items in the rate year capital expenditures inappropriately assumes that the Company is spending the same amount on these projects annually as long as the rates are in effect. The Department disallows $750,000 of capital expenditures from the Structures and Improvements category. The Department will allow the remaining $180,000 ($930,000 - $750,000) of capital expenditures in this category for the rate year.

e. New Business

New business capital expenditures refer to the installation of mains and services to connect new customers to the distribution system. For the rate year, Southern proposed $9,846,000 of new business capital expenditures, $6.7 million for new business and $3.1 million for distributed generation (DG) and peaking projects. The new business $6.7 million was determined using a five-year historical average of main and service expenditures between 2004 through 2008. New business essentially relates to new home construction and new business starts. The $3.1 million expenditure is essentially for one DG customer, which, at best, will not begin construction until December 2009 [FN1] . Reis, Dobos, Malone and McNally PFT, pp. 5-9; Response to Interrogatory GA-368; Tr. 4/13/09, pp. 475-479.

> FN1. The Company attempted to introduce new evidence in its Written Exceptions regarding this customer. See page 65 of Southern's Written Exceptions.

In its Written Exceptions, the Company argued that the 40% reduction in the new business rate base made by the Department necessitated a 40% reduction in new customer growth. The Company also stated that it will need to reevaluate whether it should continue to expend additional capital dollars to pursue new business opportunities with no ability to recover expenditures. Written Exceptions, pp. 63 and 65.

Southern provided data related to historical capital additions for new business from 1999 to 2008 and Southern's annual capital expenditures ranged between $4 million and $7.8 million. In 2009, new construction starts went down considerably while new business starts also exhibited a significant downturn. The downturn in construction experienced toward the end of 2008 and projected for 2009 was not similar to anything experienced between 2004 and 2008; the period Southern used to develop its historical average. The Company expects the oil to natural gas conversion market to be strong in 2009 given the rebates available by the State of Connecticut for high-efficiency programs and the availability of federal tax credits for equipment switching. Tr. 4/13/09, pp. 476 to 479. The table below shows new business expenditures between 1999 and 2008.

Itemized New Business Expenditures

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Year	Main Cost	Service Cost	Total Cost
1999	$2,561,100	$4,464,900	$7,026,000
2000	$2,812,800	$4,746,200	$7,559,000
2001	$1,710,500	$2,628,900	$4,339,400
2002	$1,516,200	$2,539,800	$4,056,000
2003	$2,303,600	$3,881,600	$6,185,200
2004	$2,143,000	$3,909,700	$6,052,700
2005	$2,346,300	$5,341,900	$7,688,200
2006	$1,420,000	$4,130,300	$5,550,300
2007	$1,798,800	$3,860,100	$5,658,900
2008	$2,214,600	$5,661,500	$7,876,100

Response to Interrogatory OCC-182.

OCC recommends that the level of expenditures for new business in 2009 be set at the lowest annual level experienced in the 10 year period; $4.056 million in 2002, to more reasonably reflect current economic conditions. This would reduce Southern's proposed 2009 new business expenditures by $2.7 million, or 40%, from $6.7 million to $4.0 million. Brief, p. 66. OCC's recommended expenditures failed to make a corresponding adjustment to Southern's revenues to reflect a reduction in business. OCC's recommendation also failed to take into account the Company's current strategy to market natural gas conversions to oil consumers rather than to target potential new customers. Southern Reply Brief, pp. 46 and 47.

The Department agrees with OCC concerning new business expenditures. Given the current and projected rate-year economic environment, housing and business starts can be expected to be at an all time low, not the average of five years with economically dissimilar characteristics. The Company's emphasis on energy conversions is nothing new. New business and conversion markets have been aggressively pursued since the earliest days of the natural gas industry. Whether growth from this market surpasses the expected loss from the new home and business market depends on the relationship between oil and natural gas prices more than the Company's marketing efforts. To redirect marketing dollars alone is no guarantee of sales success in a market where relative energy prices are established on the world stage and customers need to make a substantial investment in new equipment even after financial incentives.

Concerning any mismatch between new business expenditures for plant and customer growth, the Department notes that the Company failed to establish a reliable numerical relationship between the addition of new customers and the level of plant investment. While customer growth in the instant case was determined through time-series statistical analysis, pro forma new business plant investment represents a simple five-year average of recorded investments. The Company's choice

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to use a four, five or six year average is completely independent of the statistically derived level of customer growth. In the instant case, both forecasts are disjointed. If the Company had established a verifiable relationship between average customer growth and average investment [FN2] , the Department would have used this relationship to establish new business investment. Nonetheless, the relationship is not bidirectional. While it is logical to formulaically set pro forma investment levels given a specific customer count, the opposite does not follow. If it did, the Company or Department could triple annual sales by simply setting an investment levels in a pro forma rate case environment. Arguing that sales flow from an investment allowance is both illogical in a rate case environment and impractical in practice. The Department finds it difficult to believe that the Company will six months hence deny itself the revenue flow from a new customer with a favorable Hurdle Rate, because of a then historical reduction in rate base. Consequently, the Department approves a new business expenditure of $4,056,000, the same as the new business expenditure level from 2002 as this level most reflects the Department's expectations for the rate year. This results in a reduction of $2,644,000 ($6,700,000 - $4,056,000), or 40%.

> FN2. For example, every new residential heating customer connected during the test year required an average plant investment of $1,500.

The Department also disallows the total DG and peaking expenditures of $3.1 million because the connection cost for one DG special contract customer with an operational date beyond the midpoint of the rate year. The Department also reduced pro forma sales accordingly, see Section II.B. Rate Year Sales Forecast. In total, the Department approves new business capital expenditures of $4,056,000, which is a reduction of $5,790,000 ($2,644,000 + $3.1 million) from the proposed new business expenditure of $9,846,000.

f. Service Transfers

Southern defines a Service Transfer as the action necessary to move an existing service from an old main to a new main. When the Company is replacing a cast iron main with a new main, it trenches the street and installs the pipe. The new and old main could be located next to each other or the new main could be on the other side of the street depending on local conditions. At a later date, Southern would physically disconnect the existing service from the cast iron main and move it to the new main. Reis, Dobos, Malone and McNally PFT, pp. 14-15.

Southern testified that the existing service is included in rate base along with the old and new mains. Southern proposed to change its current method of capitalizing Service Transfers on a going forward basis and include this item as an expense. The Company proposed an expense of $967,000 for the Service Transfers in the rate year. Schedule C-3.37. Historically, Service Transfers were capitalized, but based on the Uniform System of Accounts the Company believes that all costs and labor related to Service Transfers should be expensed under Account 892, Maintenance of Services. Response to Interrogatory GA-395.

Southern provided several exhibits that illustrated the number of Service Transfers and the corresponding annual capitalized Service Transfer charges. A summary of these exhibits are listed in the table below:

Year	No. Transfers	Capitalized Service Transfer Charges	Meter Relocation Capitalized Expenditures	Dollars Spent on Cast Iron and Bare Steel Replacements
2006 - actual	305	$315,610	$5.3 million	$ 8 million
2007 - actual	364	$389,400	$2.9 million	$ 8 million
2008 - actual	471	$420,922	$1.5 million	$ 8 million

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2009 - proposed	880	$976,000	$1.5 million	$9.5 million

Southern stated that it was unable to provide the older data related to Service Transfers because it changed software programs during 2005. Additionally, the Company did not have a written accounting policy related to Service Transfers prior to the test year. Reis, Dobos, Malone and McNally, PFT, pp. 2-6; Response to Interrogatory OCC-219; Late Filed Exhibit No. 33.

For the rate year, Southern indicated that the proposed revenue requirement related to expensing Service Transfers would be $1,035,473 as compared to $957,765 if placed in rate base. The proposed revenue requirement related to capitalizing Service Transfers was based on the Company's proposed ROR of 10.08% and a gross revenue conversion factor (GRCF) of 1.78097. The revenue requirement associated with the capitalization of Service Transfers equals $205,179, which includes both the annual depreciation expense and the addition of half-a-year's depreciation of $31,041 for the first year. Response to Interrogatory GA-395.

The Department believes that Service Transfers are directly related to and an integral part of the Bare Steel and Cast Iron Replacement Program. This program is a capital replacement program that is intended to remove and replace specific types of mains and service connections and has been in effect for a number of years. Service connections must be relocated to a new main so that the old main can be retired. Work performed on Service Transfers is not related to maintenance of the existing service, but is directly related to the capital program for main replacements. Therefore, the Department directs the Company to include Service Transfers in rate base as a capitalized item depreciated over the service life of the asset. The proposed expense associated with Service Transfers of $967,000 is disallowed.

The Department used the actual data from 2006-2008 in the table above to verify the validity of the proposed expenditure of $967,000 for the rate year. The Department compared the largest historical expenditure associated with Service Transfers of $420,922 to the total dollars spent on the Bare Steel and Meter Relocation programs of $9.5 million during 2008. This results in a percentage of capitalized Service Transfer Charges versus Bare Steel and Meter Relocation programs of 4.43% [($420,922 / $1.5 + $8 million) * 100]. Using the calculation cited above, results in capitalized Service Transfer Charges versus Bare Steel and Meter Relocation percentage for 2006 of 2.37% and 2007 of 3.57%.

The Department calculated the capitalized Service Transfer Charges versus Bare Steel and Meter Relocation percentage of 8.80% [$967,000 / ($8 million + $1.5 million + $1.5 million)] for the proposed rate year using the above cited calculation. Based on the Department's calculation above it is obvious that the proposed rate year Service Transfer expenditure is twice as much as the historical data. However, the Company proposed an increase to the Bare Steel and Meter Relocation programs of $1.5 million. This results in a 15% increase in the dollars expended on bare steel replacements related to Southern's proposal. Therefore, Department will allow an increase in the capitalized Service Transfer expenditure of 15% or $63,138 over and above the 2008 actual expenditure of $420,922. Therefore, the rate year capitalized Service Transfer expenditure will equal $484,060 ($420,922 + $63,138).

g. Automatic Meter Reading Program

Southern's Application indicated that its automatic meter reading (AMR) is performed by Itron through a long-term meter reading contract. Schedule C-3.31. The AMR unit is a device that is attached to each meter and records the customer's monthly consumption. Southern's application shows a test year expense for meter reading of $1,779,138 with an adjustment of $56,403, for an increase in the AMR contract meter reading cost from the current $.77 to $.80 per unit effective as of June 2008. Reis, Dobos, Malone and McNally, PFT, pp. 15 and 16. Based on the proposed $56,403 adjustment, the proposed rate year meter reading expense is $1,835,541. Schedule C-3.0. Tr. 4/14/09, pp. 755-774.

Southern has 178,616 meters in service and has in-

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stalled AMR devices on 178,552 of those meters. Of the 53,504 meters in service, 49,491 are located inside homes and 4,013 in C&I buildings, which are inaccessible to the Company's employees. However, Southern obtained access and installed AMR devices on most, if not all, of the inside meters since it began installing the devices in 1998. Tr. 4/14/09, pp. 755-757 and Read-In K, Tr. 4/14/09, p. 756.

The Department congratulates Southern on its ability to install AMR devices on almost 100% of its customers' inside and outside meters. The Department approves the $56,403 adjustment to the test year and, therefore, allows a rate year expense of $1,835,541.

h. Information Technology

The Company proposed a capital expenditure of $505,600 for Information Technology for calendar year 2009, which is included in the rate year. The Company indicated that these expenditures are for information technology software / hardware, telephone equipment, and other capital office equipment. Reis, Dobos, Malone & McNally PFT, p. 10; Response to Interrogatory OCC-188. The Company did not provide sufficient information regarding these items. For example, the Department cannot determine whether these items are already in place or need to be installed. The Company provided no direct testimony. The Department disallows the capital expenditure of $505,000.

i. Tools, Shop, Garage and Safety Equipment

Southern proposed a capital expenditure of $210,000 for tool, shop, garage and safety equipment for calendar year 2009, which were included in the rate year. The Company indicated that these expenditures are for hand tools, including gas indicators, drilling/tapping equipment and supplied respirators. Reis, Dobos, Malone and McNally PFT, p. 5. The Company did not provide sufficient information regarding these items. For example, the Department was unable to determine whether these items already in place or need to be purchased. The Company provided no direct testimony. The Department disallows the expenditure of $210,000.

3. Deferred Debits - Regulatory Assets

Southern requested regulatory treatment for $54,444,606 of proposed deferred assets in the rate year, compared to $54,629,375 in the test year. In its pro forma adjustment, the Company adjusted the Department-approved regulatory asset amounts to reflect additions or reductions as well as amortization to bring the test year amounts to the midpoint of the rate year. Schedule B-6.0. In its revised filing, Southern did not reflect any adjustment to the proposed deferred assets balance amount that was proposed for inclusion in rate base. Response to Interrogatory GA-2 Corrected, Attachment 2, p. 4.

OCC recommended an expense reduction of $40,863 for deferrals as stated in Schedule C-3.13. Brief, pp. 146-148. The Department agrees with OCC's adjustment amount and reduces the unamortized deferrals and related amortization expense, See, Section II.E.1. Amortization of Deferrals Associated with DPUC Dockets.

a. Hardship Write-offs Deferred Balance

In its Application, the Company initially proposed a deferred hardship balance of $19,675,872 as of December 31, 2009 over the balance of $11,814,608 as of June 30, 2008. Southern proposed a $7,861,264 increased to the deferred amount for the 18-month period, July 1, 2008 through December 31, 2009. Based on a four-year amortization of the deferred balance, the Company requested an annual amortization of $4,918,968 ($19,675,872 / 4). RRP PFT, p. 14; Schedule C-3.6. In its revised schedules, the Company forecasted $5,798,963 as the deferred amount for the period July 1, 2008 through December 31, 2009. This forecasted amount was based on the average of the net hardship write-offs for 2006 of $6,200,285 and 2007 of $7,031,135; less the $2,749,734 allowed in base rates, and the balance extrapolated for 18 months [($6,200,285 + $7,031,135) /2 - $2,749,734] / 1.5]. Southern proposed a revised deferred hardship balance subject to amortization of $17,613,571 ($11,814,608 +

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$5,798,963) as of December 31, 2009 and a revised annual amortization expense of $4,403,393 ($17,613,571 / 4). Response to Interrogatory GA-2 Corrected, p. 29. The Company reported that the hardship deferred balance as of March 31, 2009 was $10,868,185. Response to Interrogatory GA-3, Attachment, p. 2.

OCC stated that the Company overstated its pro forma rate base by ignoring changes to the deferred hardship balance, assuming an excessive amount in the deferred balance and by using the wrong date for when new rates will be effective. According to OCC, the Company revised the deferred hardship balance used to calculate the forecasted hardship uncollectible but did not revise the hardship deferred balance included in the pro forma rate base. The pro forma deferral in the Company's proposed rate base is overstated and inappropriate because it assumes additions to the deferred balance from July 1, 2009 through December 31, 2009, six months into the new rate year. According to OCC, the proposed new annual recovery for ongoing hardship write-offs is set at a level that assumes that the annual recovery is sufficient to avoid any additions to the deferred account balance. Thus, no additional amounts should be added to the deferred balance beyond June 30, 2009. Brief, pp. 117-120.

OCC began the calculation of its recommended amounts with the deferred balance as of March 31, 2009 of $10,868,185 and added an allowed deferred recovery estimate of $468,624 for three months, April 1, 2009 through June 30, 2009. The $468,624 deferral amount for the three months April 1, 2009 through June 30, 2009 was calculated by using the recommended annual write-off of $4,624,230, subtracting $2,749,734, the amount of hardship expense currently recoverable in base rates. The difference is divided by twelve and then multiply by three [($4,624,230 - $2,749,734) / 12 x 3]. This resulted in an estimated deferred balance as of June 30, 2009 of $11,336,809 ($10,868,185 + $468,624). OCC recommended annual amortization expense of $2,834,202 ($11,336,809 / 4). After deducting the rate year amortization, the June 30, 2010 deferred balance is $8,502,607 ($11,336,809 - $2,834,202). The average deferred balance is $9,919,708 [($11,336,809 + $8,502,607) / 2]. OCC recommended customers deferred hardship write-off balance as of the midpoint of the rate year of $9,919,708, which is $7,296,680 ($17,216,388 - $9,919,708) less than the Company proposed. Also, OCC recommended $4,624,230 for the annual pro forma ongoing hardship recovery amount. This amount was derived by simply averaging the net hardship write-offs for the five years 2004 through 2008. Id.; Schedules 9 and 10.

The Department agrees with OCC that both the forecasted net hardship write-off for the calculation of the deferred balance to be amortized and the estimated annual hardship ongoing recovery amount were overstated. The Department found that the Company did not update its forecast or revise the deferred balance to reflect this updated figure. Similarly, the Department agrees with OCC that the forecasted additional write-offs included in the deferred balances should not be extrapolated to include any amount in the rate year. Expenses forecasted should be for periods subsequent to the test year, and for which data is not available, and prior to the start of the rate year, for which the pro forma ongoing recovery amount is being requested. To determine the deferred balance at the midpoint of the rate year, only half of the amortization expense should be deducted from total beginning deferred balance, or simply calculate the average of the beginning and ending balances. The Department accepts OCC's recommendation that the Company's deferred hardship balance as of midpoint of the rate year in rate base was overstated by $7,296,680 and rejects the Company's position that its overstatement was only $2.2 million. Southern Reply Brief, p. 50.

Based on the aforementioned, the Department will reduce the deferred hardship balance in rate base by $7,296,680. The Company will be directed to file an annual report detailing the balance in the deferred hardship account and changes to prior period unamortized balances. Also, any hardship write-off less than the amount allowed in base rates shall reduce the deferred balance. For write-offs above the amount allowed in base rates, the Company will be required to seek the Department's prior approval for any annual accretion to the deferred hardship balance.

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As discussed in Section II.E.7. Speedpay Transaction Fess/Kubra, Southern agreed that bank credit card fee deferrals should not be forecasted to the midpoint of the rate year. Similarly, deferred hardship expenses should not be forecasted to the midpoint of the rate year. In its Written Exceptions, the Company requested that the Department accept its calculation of deferred balances because its extrapolation of deferred expenses to the midpoint of the year is consistent with its past practice. Written Exceptions, p. 48.

The Department believes that to accept the Company's calculation because it is in concert with past practices is not a good rate-making policy. Past practices may help establish consistency but they are not regulatory binding nor are they precedent setting. For the Department to accept overstated deferred expenses calculations simply because the methodology the Company employs is consistent with past practices would not be balancing the interest of the ratepayers with that of the investors.

b. Matching Payment Plan Deferred Balance

The deferred balance for the unamortized hardship arrearage forgiveness Matching Payment Plan (MPP) as of June 30, 2008 was $18,417,665. Southern forecasted an $8,395,715 increase to the deferred amount for the 18-month period July 1, 2008 through December 31, 2009. The proposed deferred balance as of the midpoint of the rate year was $10,382,323. Schedule B-6, Lines 29 and 30; Response to Interrogatory GA-314. RRP PFT, p. 15; Schedule C-3.8. The Company testified that the deferred MPP balances as of December 31, 2008, February 28, 2009 and March 31, 2009 were $13,788,513, $11,954,365 and $11,026,650, respectively. Responses to Interrogatories OCC-217 and GA-3, p. 2.

OCC stated that the Company's proposed MPP deferred balance included in rate base was overstated because there was an excessive amount in the beginning deferred balance; the date new rates go into effect was ignored; and it included additional deferred grants for the first six months of the rate year. OCC stated that the Company's new annual recovery for MPP charges proposed for the rate year was set at a sufficient level to recover the annual arrearage forgiveness amount. Therefore, an increase to the deferral is not required for the rate year. OCC asserted that the Company's proposed MPP deferred balance as of the midpoint of the rate year is inappropriate. OCC recommended that the deferred balance included in rate base be determined by using the March 31, 2009 balance of $11,026,650, adding an estimated $1,378,548 for three months of grants for April 1, 2009 through June 30, 2009, and then deducting the current amortization of $1,251,222 for the months of April 1, 2009 through June 30, 2009. This resulted in an estimated deferred balance of $11,153,976 as of June 30, 2009. After deducting the rate year amortization of $5,004,889, the June 30, 2010 deferred balance is $6,149,087. OCC proposed an average deferred balance amount of $8,651,531 [($11,153,976 + $6,149,087) / 2] to be included in rate base or approximately $1,730,792 less than the Company's proposed amount, $10,382,323. Brief, p. 87; Brief Schedule 11.

As discussed in Section II.E.7. Speedpay Transaction Fess/Kubra, Southern agreed that bank credit card fee deferrals should not be forecasted to the midpoint of the rate year. Similarly, deferred MPP expenses should not be forecasted to the midpoint of the rate year. The Department partially agrees with OCC's calculation and recommendation. As detailed in the table in Section II.E.3. Matching Payment Plan Expenses, the Department calculated the deferred MPP balance of $7,836,696 as of December 31, 2009. This amount resulted in the reduction of $2,545,627 to the Company's proposed MPP deferred balance included in the rate base.

4. MGP Sites/Non-Utility Property Transfer

The net book value (NBV) of the Pine Street and Housatonic Avenue properties in Bridgeport and Chapel Street property in New Haven is $2,777,090. The Company proposed to reinstate it back into rate base. These properties are former manufactured gas plant (MGP) facilities that were previously in Southern's rate base. The $2,777,090 is the difference between the historical costs

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of $3,731,524 for these non-utility properties and the related reserve for accumulated depreciation of $954,434. RRP PFT, pp. 55-57; Schedules B-2.1 and B-3.0. For the MGP sites, Southern reported rental income of $222,701 for the test year and proposed $240,361 for the rate year. An O&M expense of $595,927 was reported for the test year and $704,606 was proposed for the rate year. The Company's proposal to reinstate these properties into rate base will increase revenue requirements by $498,548. Late Filed Exhibit No. 50, Attachment 1. Southern provided copies of the lease agreements for the properties at Housatonic Avenue properties in Bridgeport and Chapel Street property in New Haven. Late Filed Exhibit No. 5, Attachments 1 and 2. Regarding the facility at Pine Street in Bridgeport, the Company testified that due to complications involving environmental remediation, the lessee "has not been able to use property as of late."Tr. 04/08/09, p. 111.

Southern stated that the MGP sites were previously supported by ratepayers. Currently, all lease income associated with the properties is included in utility operating income (UOI). The Company stated that in accordance with the Decision dated July 29, 1992 in Docket No. 92-04-18,Petition of The Southern Connecticut Gas Company for Approval of Disposal of Property and Advisory Rulings Re: Proposed Accounting Treatment for Such Sale, Accounting Treatment for Leases of Corporate Headquarters and Operations Center and Accounting Treatment of Certain Costs Related to Additional Property (Property Decision), operating expenses such as property taxes and property insurance for these properties were included in UOI. Also, a portion of the Pine Street property is currently in rate base. Southern argued that in the Property Decision, the Department allowed $2,170,945, which is the cost of a bulkhead to be capitalized and included in utility plant-in-service. In the 2005 Decision, the Department allowed $3,515,929, which is the cost of the groundwater extraction and treatment system to be included in utility plant-in-service. Based on the aforementioned, the Company believes its request to reinstate these properties in rate base is justified. RRP PFT, pp. 55-57.

Southern stated that it originally asked for the removal of these properties from rate base when it was consolidating facilities in its Bridgeport and New Haven operations and had the intention to sell them. The Company determined the level of environmental contamination at the three sites and concluded that selling the properties would be very difficult. Along with the difficulty in selling, there is the possibility the Company will be holding these properties for the long term. Therefore, Southern believes it is appropriate that the MGP sites be brought back into rate base and be supported by ratepayers. Id. Southern testified that currently there are no utility operations on these facilities. It does not have any intention to conduct operations out of these facilities in the future. Tr. 04/13/09, pp. 608 and 609.

OCC noted that these properties were removed from rate base pursuant to the Department Order in the Property Decision. OCC stated that the Company acknowledged in this proceeding that despite MGP sites being removed from rate base, rental income and O&M expenses, such as property tax and insurance expenses, are included above the line in calculating UOI. See, Tr. 4/13/09, p. 609. OCC also noted that in the Property Decision, it did not oppose the allowance of these expenses in rates because the revenues from either the sales or rental would to be allocated to ratepayers. This contradicts the Company's justifications. Brief, pp. 99-102. Additionally, OCC noted the testimony on page 8 of the Property Decision which states that if the Company:

. . .were to lease these facilities some benefit would go to the ratepayers. These properties have a total acreage of 20.69 acres of land and a book value of $2,845,867. If the Company finds no alternative uses or cannot lease these properties for the benefit of the ratepayers within a reasonable period of time, the Company is directed to make a concerted effort to sell these properties. It is the Department's [sic, Authority] intention to monitor and examine the disposition of these properties and handle each transaction in accordance with established policies, taking into consideration the fact that these properties were previously in the rate base.

Id.

OCC noted that the Company acknowledged in this pro-

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ceeding that these properties are not currently used and useful and that it does not appear that they will be in the foreseeable future. OCC disagrees with the Company's proposal to reinstate the net book value associated with these properties back into the rate base and recommended that Southern's proposed rate base be reduced by $2,777,090.Id.

The Department agrees with OCC that the Property Decision allowed the inclusion of O&M expenses and property taxes associated with these properties in UOI provided the revenue received from selling or leasing these properties is allocated to ratepayers. The Company's assertion that the NBV of these properties were previously in rate base is not a prima facie reason for them to be reinstated. The timing of the Company's proposal is also questionable. In the almost 17 years since the Company requested and received approval to remove these properties from rate base, Southern had ample opportunities to discuss the difficulty it was having selling the facilities with the Department. No evidence was provided in this proceeding to indicate that the Company had sought the Department's permission to dispose of these MGP sites since the Property Decision. The Company's intention in the Property Decision included either selling or leasing these properties. The Company acknowledges that these sites will not be used for utility operations. Based on the aforementioned, the Department disallows the reinstatement of NBV of $2,777,090 related to these non-utility properties into rate base.

In its Written Exceptions, the Company stated that the lease income from the MGP properties flows to ratepayers. Written Exceptions, p. 50. However, the Company failed to mention that ratepayers currently pay O&M and environmental remediation expenses that are significantly in excess of the rental income for these properties.

5. Accumulated Deferred Income Taxes

Southern proposed regulatory treatment for $41,384,854 of accumulated deferred income incomes taxes (ADIT) in the rate year or a $6,367,162 increase of the test year amount of $35,017,692. Schedule B-7.0. As a result of the Department's inquiry regarding Federal bonus depreciation in 2009, Southern revised the rate year's ADIT to $46,378,930. This adjustment was primarily due to the increase in the rate year's depreciation ADIT from $48,310,092 to $52,981,259. The Federal economic stimulus bill provides bonus depreciation allowance for the costs of qualifying capital expenditures incurred in 2009. Tr. 05/05/09, pp. 2345 and 2346; Late Filed Exhibit No. 11 Supplemental; Response to Interrogatory GA-2 Corrected, Attachment 2, p. 15.

The Sarbanes-Oxley Act of 2002 created the Public Company Accounting Oversight Board (PCAOB), a private nonprofit corporation charged with overseeing the auditors of public companies. The goals of the PCAOB include protecting the public and investors' interest by promoting informative, fair and independent audit reports. In its Application, Southern proposed amortizing an unidentified accumulated deferred tax balance Tax Basis Balance Sheet (TBBS) adjustment of $4.2 million over four years. This expensing of accumulated deferred income taxes (ADIT) items would result in a proposed amortization charge of $1,059,663 for the rate year. Further, that the attestation of accumulated deferred income tax balances is one of many areas emphasized by PCAOB. The Company stated that Utility Shared Services Corporation (USSC) TBBS tracks and verifies all accumulated deferred income tax balances. The Company stated that the TBBS began with accumulated deferred income tax balances as of January 1, 2000. Variances between the TBBS and book balances were grouped into categories, which include tracking differences between book balances and unidentified accumulated deferred income tax balances. RRP PFT, pp. 49 and 50; Responses to Interrogatories GA-316 Attachment 2 and OCC-73; Schedule B-7.0; Tr. 4/08/09, pp. 139-143. The Company included in rate base $3,708,820 for unidentified ADITs with temporary differences. Schedule B-7.0. The Company proposed to amortize $4,238,652 of ADITs with temporary difference over four years. This resulted in annual amortization expense of $1,059,663. Schedule C-3.59. Also, Southern included Connecticut Corporation Business Tax (CCBT) and Federal incomes tax (FIT) of $70,921

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and $988,731, respectively, in the total income tax expenses. Schedules C-3.54 and C-3.55. Coincidentally, the total income tax expense related to unidentified deferred taxes is the same amount as the annual amortization expense The Company's witness testified that the proposal to amortize TBBS related ADIT is "one-of kind" and that in his 11 years with the Company, a similar proposal has never been made. Tr. 04/08/09, p. 168.

The Department disagrees with the Company's proposal to amortize ADITs related to these TBBS adjustments. Section 103 of the Sarbanes-Oxley Act of 2002 instructs the PCAOB to establish audit and attestation, quality control, ethics, and independence standards and rules for auditors of public companies to be used for preparing and issuing audit reports. The Company failed to adequately explain how Section 103 specifically affected its treatment of the ADITs for the unidentified items or that ADITs should be expensed for rate-making purposes. Also, Southern failed to indentify which PCAOB's standard specifically emphasized the attestation of ADITS and did not explain if its public accountants had recommended the proposed treatment.

The Department treats ADITs, identified and unidentified, as offsets to rate base items for which recoveries or recognition has being temporarily deferred. The mere fact that the Company's affiliate tracks and attests to the existence of the differences between book balances and unidentified accumulated deferred income tax balances is not a justification for the proposed amortization. The Department assumes that the Company tracks and attests to the existence of all other ADITs, identified and unidentified, and underlying regulatory deferred assets or liabilities. Perhaps more worrisome of this proposal is the fact that the $4.2 million amount had already offset other ADITs used to reduce rate base. Absent this amount, the ADITs would be $39,256,344 ($35,017,692 + $4,238,652) to offset rate base for the test year. See, Schedule B-7.0. The Company testified and acknowledged that deferred taxes will eventually turn around and that the turn around period depends on the length of the underlying assets. Tr. 05/07/09, pp. 2343 and 2344.

The Department does not believe it is proper or in the public interest to charge currently non-incurred and non-regulatory expenses to ratepayers and then subsequently credit back the same charges to them. ADITs, credits or charges, are not regulatory items subject to amortization. Based on the aforementioned, the amortization expense of $1,059,663 related to these unidentified ADITs is disallowed. Also, the Department disallows the income tax expense of $1,059,663 related to the "unidentified" deferred taxes. This reduction composed of $70,932 and $988,731 for CCBT and FIT, respectively, which the Company included in the total pro forma income tax expenses at present rates. See, Schedules C-3, p. 2; C-3.54, p. 3 and C-3.55, p. 3; Response to Interrogatory GA-2 Corrected Attachment 2, pp. 42 and 45. Also, as a result of SFA, the revenue requirements model used by the Department increases proposed CCBT and FIT expenses by $135,459 and $584,730, respectively. This resulted in a net increase of $66,527 ($135,459 - $70,932) to the proposed CCBT and a net decrease of $404,001 ($988,731 - $584,730) to the FIT expenses at present rates.

In its Written Exceptions, the Company incorrectly stated that the Department disallowed the $4.2 million adjustment to ADIT for TBBS in rate base. Written Exceptions, p. 68. The Company's statement was not accurate because the Department did not increase ADIT for this adjustment. As indicated above, the Department disallowed the amortization of the deferred tax adjustment for the reasons specified. The Company also stated that a similar adjustment was not made in the Decision for Docket No. 08-12-06.While the Department attempts to be consistent in its adjudication of similar matters, obviously the determination of certain issues that were raised and litigated are reviewed in the context of each individual proceeding. For instance, as indicated above, the Company acknowledges that there is a Federal bonus depreciation in 2009 and accordingly proposed to increase the rate year's ADIT. This issue was not addressed in the CNG proceeding. Further, the Company focuses its Written Exceptions on why a similar adjustment was made in the CNG case and not on the merit of amortizing a deferred tax item. Southern's ratepayers should not have to pay for an expense because a similar adjustment was not addressed in CNG's case.

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6. Cash Working Capital

a. Introduction

It is a customary regulatory practice to allow an adjustment to rate base in recognition of the timing difference between when revenues are received and when expenses are paid out. For larger utilities, the Department typically prefers that a lead/lag study be conducted to determine the appropriate cash working capital allowance rather than using some rule of thumb approach or the utility's balance sheet result. In this proceeding, Southern conducted such a lead/lag study and requested that the results of that study be used for determining its rate year rate base.

The Company hired Gary Shambaugh of AUS Consultants to perform the lead/lag study. In conducting his study, Mr. Shambaugh measured the collection lag portion of the revenue lag by dividing total customer payments into the sum of the daily accounts receivable balances. Shambaugh PFT, pp. 10 and 11. He calculated specific expense leads for 23 different expense and income categories, including non-cash categories such as depreciation, deferred taxes, amortization and balance for common. Exhibit WC-1, p. 21. The results of the study indicated a cash working capital requirement for the rate year of $54,306,023. Revised Schedule WPB-4.0b. The Department reviewed Southern's cash working capital request and finds it acceptable except as discussed below.

b. Lead/Lag Study

i. Non-cash Items

During the hearings in this case and in its brief, OCC argued that non-cash expenses and income should not be part of the lead/lag study. They do not involve an outlay of cash and are not part of a traditional method of determining cash working capital. Brief, pp. 88-91; Tr. 4/16/09, pp. 1157 and 1158; Administratively Noticed Docket No. 08-12-06, Tr. 3/25/09, pp. 1490-1506. In reviewing this issue, the Department looked at the impact of such non-cash expenses and income on rate base and/or on the assumptions underlying related portions of the case. With regard to depreciation; deferred taxes and amortizations, these expenses reduce rate base as they occur. This deprives the Company of a return on investment while it waits to recover the expense through rates. As such, these non-cash items are appropriately part of the lead/lag study. With regard to Balance for Common, the return on equity used to calculate the balance is determined from market data assuming an annual return with a quarterly dividend requirement. See, Section II.R.5. Cost of Equity below. This assumption creates the timing by which the income is needed for the Company to be made whole relative to this element, making this category appropriate for inclusion in the lead/lag study. For these reasons, the Department will not adjust the Company's study for non-cash items.

ii. Use of Receivable Balances to Calculate Collection Lag

While the Department does not object to the Company's use of the sum of the daily accounts receivable balances in calculating the collection lag, this method of calculation has implications on how uncollectible expense should be treated in the lead/lag study. Accounts that are ultimately written-off as uncollectable are part of the accounts receivable balance until they are written off. This method of calculating the collection lag grants the Company a return on uncollectable expense through the cash working capital adjustment until write-off. Response to Interrogatory GA-418; Tr. 4/16/09, pp. 1123-1126. In recognition of this, the Company removed uncollectible expense from its lead/lag study. Response to Interrogatory GA-446; Revised Schedule WPB-4.0b. The impact of this removal is equivalent to assigning uncollectible expense a net lag of zero, which for the Company equates to an expense lead of 92.23 days. Tr. 4/16/09, pp. 1137-1141; Response to Late Filed Exhibit No. 79. Rather than removing uncollectible expense from the lead/lag study (i.e., arbitrarily assigning the expense a lead of 92.23 days as proposed by the Company), the Department finds it more appropriate to keep uncollectible expense in the study and assign it a more reasonable expense lead as discussed below in Section II.C.6.d.ii. Uncollectible Expense.

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iii. Rate Base Prepayments

During the course of this proceeding, both OCC and Department staff noted that the Company had included expense categories in its lead/lag study that it had already included in rate base as prepayments; notably, insurance and property taxes. Tr. 4/9/09, pp. 250-252; Tr. 4/13/09, pp. 584-585; Schedules WPB-4.0b and B-5.0. The Company agreed that the prepayment nature of these expenses need only be accounted for once; either in the lead/lag study or directly in rate base as a prepayment. Tr. 5/7/09, pp. 2360-2361. The Company proposed to address the issue by removing the items from its lead/lag study. Response to Late Filed Exhibit Nos. 14 and 45; Revised Schedule WPB-4.0b. However, the Department believes it more appropriate to include these items in the lead/lag study and remove them as prepayments in the rate base. This is because the lead/lag study directly measures the net lag and daily expense associated these items and assigns them rate base treatment based on that net lag and daily expense level. Schedule WPB-4.0b. The Company did not explain the basis for the various prepayments in rate base, but these prepayments are likely based on a historical average as was the case for Southern's sister company CNG. CNG Rate Case Decision, p. 22. Therefore, the Department will remove insurance and property taxes from prepayments in rate base and include these items in the lead/lag study.

c. Revenue Lag

i. Update of Lag

During the hearing, the Company indicated that its collection lag decreased due to the Company's collection efforts and provided updated information on its collection lag. Tr. 4/16/09; pp. 1121-1123; Late Filed Exhibit No. 78. In its Brief, OCC quantified the decrease to the lag based on this updated information as equal to 10.92 days. Brief, pp. 91-93. However, as pointed out by the Company in its Reply Brief, OCC's quantification ignores the seasonality of the accounts receivables balance relative to collections and greatly distorts the quantification by using an updated year comprised of two first quarters, one second quarter and one fourth quarter (no third quarter). Reply Brief, p. 52. Comparing the results of first quarter 2008 with first quarter 2009, appropriately takes into consideration seasonality and indicates an updated revenue lag that is 2.5 days less than the test year results would indicate. Late Filed Exhibit No. 78, Attachment 2. As such, the Department reduces the Company proposed collection lag 2.5 days.

ii. Change to Charge-Off Policy

In Response to Interrogatory GA-418, the Company proposed to accelerate the charge-off period for uncollectibles from six months to three months. Response to Interrogatory GA-418. The Company agreed to calculate the impact of the policy change on working capital if the proposal was approved. Tr. 4/16/09, p. 1127. The Department believes that shortening the charge-off period from six months to three months is appropriate and consistent with the Company's more aggressive approach to collections. In addition, it provides for accounts receivable balances that are more in line with what those balances are actually worth (i.e., collectible). The Department approves the proposed policy change.

Changing from a six-month charge-off policy to a three-month charge-off policy has two largely off-setting impacts on working capital: 1) it reduces the collection lag as measured by the Company by reducing the accounts receivable balances; and 2) it reduces the expense lead for uncollectibles. See, Section II.C.6.d.ii. Uncollectible Expense. The Company calculated that the impact on the collection lag would be a 4.44 day reduction. Late Filed Exhibit No. 78, Attachment 1. In its Reply Brief, the Company argued that incorporating the impact on the collection lag would only be agreeable if Southern was allowed amortization of the one-time write-off associated with the change in policy (i.e., write-off of three months of "uncollectible" receivables). Reply Brief, p. 53.

The Department disagrees that the one-time write-off has ratemaking implications. The uncollectible expense as used for ratemaking is a prospective expense inten-

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ded to represent the amount of current revenues that will ultimately prove uncollectible. Tr. 4/16/09, pp. 1133-1135. In addition, there is no ratemaking provision whereby uncollectible write-offs are compared with pro forma uncollectible expense and trued-up in future ratemaking proceedings. As such, neither the length of time "uncollectibles" are held as receivables nor the amount of write-offs taken or not taken at any given point in time impacts the amount ultimately proving to be uncollectible. Therefore, the Department reduces the proposed collection lag an additional 4.44 days for this policy change and makes a mitigating reduction to the uncollectible expense lead in Section II.C.6.d.ii. Uncollectible Expense, below.

In Written Exceptions, the Company claimed that it will not implement the change to the charge-off policy unless Southern "... is permitted to book the actual one-time expense in a deferred account at the beginning of the rate year and begin recording amortization expense annually as proposed."Written Exceptions, p. 47. While the Department does not believe that the policy change materially impacts revenue requirements due to the largely off-setting impacts on revenue lag and uncollectible expense lead, there are benefits to shortening the charge-off period. As identified above and in Section II.E.10. Non-Hardship Net Write-Offs, these benefits include consistency with the Company's more aggressive collection approach, more accurate valuation of its accounts receivable balances, improvement of its collection cycle and alignment with the practice of its sister company, CNG. As such, the Department will not leave this policy change to the discretion of the Company and hereby directs Southern to implement this policy change.

iii. Purchased Gas Cost Related Revenues

In developing the service lag portion of the revenue lag for the Company, Mr. Shambaugh assumed that meters are read at the end of the month or billing cycle for service rendered during the month or cycle. This assumption resulted in a service lag of 15.22 days; the average number of days from the midpoint of the billing cycle to the end of the billing cycle. Southern Exhibit WC-1, pp. 7-9. While this is the case for revenues associated with almost all expense categories, it is not the case for revenues associated with purchased gas costs. Unlike other revenues, these revenues are trued-up and recovered through the purchased gas adjustment clause (PGA). This clause recovers purchased gas costs based on sales billed during the month, not on sales accrued or delivered during the month. As such, meters are read during the month and trued up through the PGA for service provided during the month. Tr. 4/9/09, pp. 246-250. This action by the PGA effectively aligns meter reads with service rendered and eliminates the service lag. For purchased gas cost related revenues, meter reads are centered on the midpoint of the month or billing cycle for service centered on the midpoint of the month or billing cycle. Tr. 4/16/09, pp. 1114-1119. In this case, the service lag is zero. For this reason, the Department reduces the revenue lag associated with purchased gas cost related revenues by 15.22 days.

In Written Exceptions, the Company disputed that the PGA impacts the service lag for purchased gas costs. Written Exceptions, pp. 40-45. However, the Company's logic is flawed because it assumes in its arguments that the billing cycle and service period are one and the same. In the case of the PGA and purchased gas costs, this is not the case. By using billed sales to recover purchased gas costs instead of accrued sales, the PGA effectively uses a billing cycle centered on the beginning of the service period. As such, the billing cycle predates the service period by a half-month; equivalent to the service lag. To align the purchased gas cost related revenues collected through the PGA with the service period purchased gas costs incurred by the Company (to determine the net lag associated with purchased gas costs), an amount of time equivalent to the service lag must be subtracted from the normally calculated revenue lag. The Department has appropriately done that by reducing the revenue lag associated with purchased gas costs 15.22 days.

d. Expense Leads

i. Affiliate and Corporate Charges

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In its Brief, OCC challenged the expense lead days associated with affiliate and corporate charges used in the Company's lead/lag study. Brief, pp. 96-97; Brief Schedules. While the lead/lag study result was based on the measured timing of payments from Southern to affiliates for service rendered, OCC argued that contractual obligations between Southern and its affiliates better represents the cash working capital requirements associated with this expense category. The Department agrees. For transactions between affiliated entities, where incentives to best manage a company's cash flow is diminished, contractual obligations often provide a better measure of working capital needs than past practice. OCC recommended a 50.00 day lead for these expenses for Southern based on a 15-day service lag, 5-day billing lag, and a contractual 30-day collection lag limit for the affiliates. Brief, p. 96. While the Department agrees with the basis for calculating the expense lead, the assumed billing lag is excessive, particularly given Southern's own measured billing lag of less than 2 days. For this expense category, the Department will use a lead of 47.00 days (15 + 2 + 30) instead of the Company proposed lead of 38.39 days.

ii. Uncollectible Expense

The Company initially proposed a 15.00 day lead for uncollectible expense before removing the expense from the lead/lag study as discussed in Section II.C.6.b.ii. Use of Receivable Balances to Calculate Collection Lag above. Also as discussed in that section, the Department found it appropriate to keep uncollectible expense in the lead/lag study and to assign it an appropriate amount of lead days. To determine the appropriate amount of lead days to use for uncollectible expense, the Department reviewed the amount of time receivables, that are eventually written off as uncollectible, remain in the receivable balance. Under the Company's new policy approved in this Decision (see, Section II.C.6.c.ii. Change to Charge-Off Policy above), it will be the Company's policy to write-off an account as uncollectible 90 days after the account has been closed if there has been no activity in the account during those 90 days. Tr. 4/16/09, pp. 1123-1128.

Also, prior to the account being closed there is also a time frame during which receivables are carried. Combining the time receivables are in the receivables balance before an account is closed with the time they are in the balance after the account is closed (at least 90 days) creates a minimum time uncollectible receivables are in the balance of approximately 180 days. In addition, hardship accounts and inside meter accounts which are hard to close due to legal protections and access difficulties, makes uncollectible expense associated with these accounts likely to have been in the receivables balance much longer than 180 days. Indeed, the average hardship account has been in the receivables balance for 421 days. Shambaugh PFT, p. 12; Tr. 4/16/09, p. 1120. Given a range of 180 days to in excess of 421 days and with hardship related uncollectibles accounting for approximately 35% of uncollectible expense, the Department finds 260 days an appropriate lead time for uncollectible expense.

In Written Exceptions, the Company argued that the Department's inclusion of uncollectible expense in the working capital study and use of a 260-day lead is based on an assumption that the Company is recovering this expense before it actually incurs it. Written Exceptions, p. 46. This is not the case. As with any expense, the Company incurs uncollectible expense when it renders service. The purpose of a cash working capital study is to determine when cash reimbursement for that expense is needed by the Company. When uncollectible expense is incurred by the Company as service is rendered, this expense is carried in the accounts receivable balance and earns a return as part of the calculated revenue lag. It is only when the associated receivable is written-off much later (260 days later as determined above) that the Company no longer gets a return on it and, thus, needs the cash reimbursement. Using a shorter expense lead for uncollectible expense would in effect provide the Company with a cash reimbursement while it is still receiving a return.

iii. Injuries and Damages Expense

In its Brief, OCC recommended that the self-insured portion of the injuries and damages expense be based on

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a five-year average of the actual claims paid with no further build up of the reserve. Absent the reserve build up, the expense lead for this item can be reduced from the Company proposed negative 180 days to the positive 60.66 days proposed for "other operating and maintenance." Brief, p. 95. The Department does not find a compelling reason to change this expense from a funded reserve expense to a pay-as-you-go expense as presented by OCC. Indeed, the Company cautions that OCC's approach may result in the Company experiencing claims greater than allowed. Reply Brief, p. 53. While the reserve approach causes an increase to working capital, the created reserve also serves as an offset to rate base. It ensures that under almost all situations, the Company will have a sufficient amount available to pay injuries and damages claims. Therefore, the Department will allow the proposed negative 180-day expense lead for this expense.

e. Adjustments to Expense Amounts

In addition to adjustments to the lag and/or lead days of some expense categories, the Department also made adjustments to the amount of expenses or income allowed for ratemaking purposes. These adjustments are detailed throughout this Decision and impact the cash working capital the Company needs. The Department adjusted the expense and income levels used to calculate the cash working capital needs of the Company to mirror the expense and income levels allowed by this Decision.

f. Conclusion on Cash Working Capital

Based on the adjustments detailed above, the Department calculates a cash working capital requirement for the Company of $33,281,034. This amount is $21,024,989 less than the $54,306,023 proposed by the Company. As such, the Department reduces cash working capital by $21,024,989.

7. Conclusion on Rate Base

In addition to the noted specific adjustments to rate base discussed in this Decision, the revenue requirements model used by the Department further adjusts rate base for the impacts of specific adjustments on deferred taxes and accumulated depreciation. With all the adjustments, the Department finds that the appropriate rate base for the Company is $436,790,282. Table I in the Appendix shows the rate base presented by the Company and as adjusted by the Department.

D. REVENUE AND REVENUE ADJUSTMENTS

The Company's original filing showed actual test year revenues, including PGA revenues, of $398,938,076. Pro forma revenues at present rates amounted to $443,007,506, an increase of $44,069,430 to reflect pro forma sales adjustments. The Company then requested a revenue increase of $50,091,972 to arrive at total operating revenues at proposed rates of $493,099,478. Schedule C1/C2. Subsequent revisions and corrections made throughout the case resulted in a revised revenue request. While test year revenues remained the same, pro forma revenues at present rates was reduced by $14,535,830 to arrive at $384,402,246. This sizable reduction reflects nearly a 25% reduction in total gas costs. Finally, the Company's originally proposed revenue increase of $50,091,972 was reduced to $34,179,309, a reduction of $15,912,663, or 32%. Revised pro forma revenue at proposed rates requested by the Company now amounts to $418,581,555, which represents a total decrease of $74,517,923 ($493,099,478 - $418,581,555) or 15.1%. Response to Interrogatory GA-2 Corrected, Revised C1/C2.

Due to the Department's adoption of a different sales forecast, pro forma revenue at present rates is increased from the Company's Final Proposed Forecast by $4,261,093 to $388,663,339. See, Section II.B. Rate Year Sales Forecast. The Department's disallowance of the Company's proposed expansion of daily demand meters (DDM) to Rate RMDS residential customers reduces pro forma revenue at present rates by $27,518. See, Section II.K.5.c. Residential Multi-Dwelling. This adjustment reduces pro forma revenue at present rates to $388,635,821.

E. EXPENSES AND EXPENSE ADJUSTMENTS

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1. Amortization of Deferrals Associated with DPUC Dockets

Southern proposed the recovery of three categories of deferred costs associated with Department dockets. First, the Company proposed the recovery of an unamortized balance of $750,326 for deferred costs from various Department dockets that were approved for recovery in the 2005 Decision. Second, Southern proposed for recovery the annual amortization expense of $400,000 for the deferred costs of $3,261,750 that were related to the 2005 Decision and is currently being amortized over 6.2 years. Lastly, the Company proposed recovery of $243,524, an amortization expense based on four-year period to recover $974,095. The latter amount represents the deferred costs associated with various Department dockets that have occurred since the 2005 Decision. The total rate year amortization amount requested is $1,393,850 ($750,326 + $400,000 + $243,524) or $186,975 above the test year amount of $1,206,875. Schedule C-3.13; RRP PFT, p. 30.

According to OCC, the Company's responses to inquiries in this proceeding indicated that many of the estimated Department deferrals are unsupported. This is because the majority of the Company's estimated deferred costs, for the Department dockets incurred by the end March 2009, show zero deferred costs projected beyond that date. Therefore, OCC recommended that these estimated deferrals be removed from the deferred costs and referenced responses to its audit request ODR-14, Attachment 2 Supplement and Late Filed Exhibit No. 41. OCC recommended that the total deferrals from the Department dockets of $810,647 be amortized over a four-year period. This results in an annual amortization expense of $202,662 or $40,863 less than Southern's pro forma adjustment of $243,524. Brief, pp. 146-148.

The Department agrees with OCC analysis and the assertion that several of the proposed deferred balances are not supported by the record in this proceeding. Therefore, the Department reduces the amortization expense of deferred costs related to the Department dockets by $40,863 [($974,095 - $810,647) / 4] or $163,448/4. In the interim period, the Company is not allowed a return of or on such assets. The Department will also reduce rate base by $974,095.

The Department intends to halt the practice of deferring Department docket expenses between rate cases. The Department docket expenses are generally nonmaterial, recurring expenses where deferrals should not be used. The Department notes that deferrals can lead to unintended consequences. For example, the act of deferring expenses for future recovery has resulted in the request to continue the write-down of costs associated with a 1999 rate case, despite an intervening rate case. These, and apparently other deferrals that pre-existed even the prior rate case, are being presented here despite the fact that the Company enjoyed significant overearnings from the rates established therein. The Department halts additional deferrals of Department docket expenses.

2. Hardship Program Expenses

In the 2005 Decision, the Department allowed an annual amortization of deferred balances of $436,671 for the Hardship Grant Program (HPG) and $5,004,889 for the deferred hardship arrearage forgiveness MPP. For the 2005 Decision's rate year and periods subsequent, the Department allowed annual expenses of $3 million and $6 million for the HPG and MPP, respectively. Additionally, $2,749,734 in hardship uncollectible expense was allowed to be recovered in rates. See, 2005 Decision.

In this Application, the deferred balance for hardship uncollectible as of June 30, 2008 was $11,814,608. Southern originally proposed $7,861,264 increased to this amount for the 18-month period, July 1, 2008 through December 31, 2009. This resulted in a total deferred balance amount of $19,675,872 ($11,814,608 + $7,861,264) as of December 31, 2009. The Company requested an annual expense of $4,918,968 ($19,675,872 / 4) based on four-year amortization of the deferred balance. For the annual pro forma ongoing hardship recovery, Southern originally proposed $5,625,100 for the rate year. This amount was calculated by averaging the net hardship write-off amounts for four years 2004 through 2007 without adjusting for the $2,749,734 re-

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covered in base rates. The Company added $5,625,100 to the proposed amortization expense to produce a rate year total hardship uncollectible expenses of $10,544,068 ($4,918,968 + $5,625,100), which is an increase of $7,794,334 over the test year amount of $2,749,734. RRP PFT, p. 14; Schedule C-3.6. In its revised schedules, the Company reduced its proposed uncollectible hardship expense by $1,350,259 to $9,193,993, which is $6,444,259 over the test year. The Company's revised proposal includes $4,403,393 for the amortization of the revised deferred balance of $17,613,571 and $4,790,600 for the revised annual pro forma ongoing hardship recovery for the rate year. Response to Interrogatory GA-2 Corrected, p. 29.

OCC argued that the Company's proposed hardship expense was overstated because it captured only some of the efforts of the aggressive collection efforts; assumed an excessive amount in the deferred balance; ignored the planned date for new rates to go into effect and ignored the effect of an increase in hardship grants. While the Company's four-year average of the 2004 through 2007 net hardship write-offs has some smoothing; it ignores the significant decline in the percentage of net write-offs to hardship revenues from 20.94% in 2007 to 10.29% in 2008. Thus, OCC recommended that a five-year average of 2004 to 2008 levels be used to reflect the annual write-off of hardship accounts on a going forward basis. The use of a five-year average produces $4,624,230 of annual write-off or $166,370 less than Company's request of $4,790,600. Brief, pp. 112-120.

OCC also argued that the amortization expense of $4,403,393 for the deferred balance proposed by the Company is overstated. It began with the June 30, 2008 deferred balance of $11,814,608 and extrapolates deferred forecast for the 18 months ending December 31, 2009. Also, the deferral balance of $17,613,571 is overstated because the Company used an old deferred balance, assumed an excessive amount of annual write-off and that the amortization expense was based on the December 31, 2009 balance, approximately six months into the proposed rate year. OCC recommended that June 30, 2009 deferred balance is the appropriate balance to determine the deferred balance to be amortized. OCC began its calculation of the June 30, 2009 balance with the deferred balance as of March 31, 2009 of $10,868,185 and added an allowed deferred recovery estimate of $468,624 for three months April 1, 2009 through June 30, 2009. Response to Interrogatory GA-3, p. 2. This resulted in an estimated deferred balance as of June 30, 2009 of $11,336,809 ($10,868,185 + $468,624). OCC recommended an annual amortization expense of $2,834,202 ($11,336,809 / 4).

Also, OCC recommended $4,624,230 for the annual pro forma ongoing hardship recovery amount. This amount was derived by simply averaging the net hardship write-offs for the five years 2004 through 2008. The $468,624 deferral amount for the three months April 1, 2009 through June 30, 2009 was calculated by using the recommended annual write-off of $4,624,230, subtracting $2,749,734, the amount of hardship expense currently recovered in base rates. The difference is divided by twelve and multiply by three [($4,624,230 - $2,749,734) / 12 x 3]. OCC recommended a total hardship expense of $7,458,432 for the rate year. This amount is composed of the sum of the annual hardship write-off of $4,624,230 and annual amortization of $2,834,202; and is $1,735,561 less than Company's proposed total rate year hardship expense of $9,193,993. Id., Schedules 9 and 10.

The Department thoroughly reviewed and analyzed the Company's proposed hardship expense for the rate year. The twelve-month balances of hardship receivables for active accounts and the amounts of gross and net hardship write-offs are listed in the table below:

12-Months Ending	Hardship A/R	Gross Write-Offs	Net Write-Offs
December 2005	$23,221,187	$3,696,439	$3,001,641
December 2006	$22,761,142	$6,200,285	$6,200,285

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December 2007	$25,080,013	$8,852,844	$7,031,135
December 2008	$21,774,022	$5,652,791	$3,958,947

Response to Interrogatories OCC-33, Attachments 1-3, Supplement Attachment, and GA-281 Attachment.

The Department found that both the forecasted net hardship write-off for the calculation of the deferred balance and the estimated annual hardship ongoing recovery amount were overstated. The hardship deferred balance as of March 31, 2009 was $10,868,185. See, Response to Interrogatory GA-3, Attachment, p. 2. The Company failed to update its proposed hardship forecast to include this figure. Similarly, the Company failed to update its hardship forecast to incorporate the latest net hardship write-off for calendar year ending December 2008. For the calendar year ending 2008, active account receivable (A/R) from hardship customers shows a noticeable decline in 2008 compare 2007 despite an increase in total hardship revenue from $33,571,965 in 2007 to $38,457,988 in 2008. See, Responses to Interrogatories OCC-33, Attachment 1, p. 19, Attachment 2, p. 7, Attachment 3, p. 8 and OCC-33 Supplement Attachment. The average of 2004 through 2007 net hardship write-offs does not correctly reflect the outcome of efforts the Company had made to reduce its hardship write-offs since 2005. It also does not incorporate the precipitous decline in commodity costs of natural gas from their high levels in the summer of 2008. It is the Department's opinion that to deliberately neglect the impact of the declines in both hardship A/R and the net write-off in 2008 is not balancing the needs of the Company with the interest of the ratepayers. The Department found OCC's recommendation to use the five-year average, which includes the 2008's net write-off amount, to calculate the deferred forecast for three months April 1, 2009 through June 30, 2009 appropriate and reasonable. Thus, the Department accepts OCC's recommendation of $2,834,202 as the annual amortization of the deferred balance for hardship net write-offs.

The Department rejects both the Company's proposed recovery of ongoing annual hardship expense of $4,790,600 and $4,624,230 recommended by OCC. The Department believes the Company's aggressive efforts are also having positive impacts on the hardship write-offs. This is supported by the significant decrease in the net hardship in 2008 compare to the 2007 amount. The unamortized or net increase to the deferred balance in 2007 was $4,281,401 ($7,031,135 - $2,749,734) and $1,209,213 ($3,958,947 - $2,749,734) in 2008. Given this trend, the significant decline in commodity gas costs, and the aggressive collection efforts already in place, the Department expects the net hardship write-offs for the rate year to be less than the 2008 level. The Department concludes that the ongoing annual hardship expense should remain at the current level of $2,749,734. Therefore, the total allowed rate year's hardship expense is $5,583,936, which consists of annual amortization of the deferred balance of $2,834,202 and the annual hardship write-off of $2,749,734. The Department disallows $3,610,057. The Department believes allowing a hardship expense above the allowed amount will put an undue burden on ratepayers. It will negatively mitigate the positive results of the aggressive collection efforts the Company has and is proposing to put in place.

3. Matching Payment Plan Expenses

Southern proposed to continue the annual deferred hardship arrearage forgiveness MPP amortization expense of $5,004,889 for prior period's deferred balances. For the ongoing annual MPP expense, the Company proposed a rate year amortization expense of $5,847,447, based on a three-year average of MPP charges for 2005 through 2007. This resulted in total rate year's MPP expenses of $10,852,336 ($5,004,889 + $5,847,447), which is $152,553 less than the test year amount of $11,004,889. The Company originally reported deferred MPP of $18,417,665 as of June 30, 2008 and forecasted an $8,395,715 increase to the deferred balance for the 18-month period, July 1, 2008 through December 31, 2009. The proposed deferred balance as of midpoint of the rate year included in rate base was $10,382,323.

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Schedule B-6, Lines 29 and 30; Response to Interrogatory GA-314; RRP PFT, pp. 15 and 22; Schedule C-3.8. Subsequently, the Company testified that the deferred MPP balances as of December 31, 2008, February 28, 2009 and March 31, 2009 were $13,788,513, $11,954,365 and $11,026,650, respectively. Responses to Interrogatories OCC-217 and GA-3, p. 2. In its revised filing, the Company did not make any adjustment to the proposed MPP deferred balance or to the MPP expense.

OCC stated that the Company's proposed rate year MPP expense was overstated because it does not reflect the continued trend of lower MPP charges; it assumes an excessive amount in the deferred balance; and it ignores the planned date new rates go into effect. OCC recommended an annual ongoing MPP expense of $5,514,192 based on a four-year average of the MPP awards from 2005 through 2008, which is $333,255 less than $5,847,447 proposed by the Company. Brief and Schedule 11.

The Department found that both the forecasted MPP grants added to the deferred balance for amortization and the estimated annual MPP amount were overstated. The Company testified that the unamortized deferred MPP balance as of March 31, 2009 was $11,026,650 and the MPP expense for 2008 was $4,514,429. Responses to Interrogatories OCC-217 and GA-3, p. 2. The Company failed to update its proposed deferral and expense requests to incorporate this available information. Additionally, the Department reiterates its position that the Company should not be forecasting or extrapolating expense amounts into the rate year while at the same time estimating additional annual expense to be recovered in the rate year and beyond. It is the deduction of the half-year amortization expense from the beginning deferred balance that brings the deferred balance to the midpoint of the rate year level not forecasting 18 months worth of expenses while at the same time deducting a half-year amortization amount.

The Department disagrees with both the Company's proposed use of a three-year average and OCC's recommendation to use a four-year average of the matching awards to calculate both the pro forma level of ongoing MPP amortization expense and for forecasting the deferred amount from April 1, 2009 to June 30, 2009. Both approaches ignore the noticeable downward trend in the level of MPP grant funding since 2006. The Department believes $4,514,429, the MPP charges for 2008, is a better proxy for the pro forma annual MPP amortization for the current energy assistance grants. The forecasted deferred amount for the three months April 1, 2009 to June 30, 2009 is $1,128,607 ($4,514,429 / 4). For these three months, the prior balance amortization expense was $1,251,222 or 25% of $5,004,889, the annual prior balance amortization expense allowed in the 2005 Decision.

In its calculation of the deferred balance as of July 1, 2009, OCC failed to deduct and reduce the deferred balance by $1,500,000 for April 1, 2009 to June 30, 2009. This amount represents the three months portion of the $6,000,000 current balance amortization expense allowed in rates in the 2005 Decision. Also, the Department found OCC's recommendation to continue to allow $5,004,889 as the annual amortization expense for prior deferred balance puzzling giving its calculation that the unamortized balance of the deferred MPP as of July 1, 2009 is $11,153,976. The Department does not believe it is in the public interest to continue to apply this high amortization level given the deferred balance amount at the beginning of the rate year and the current economic crisis. The Department will amortize the revised deferred balance as of June 30, 2009 over three years. The calculations of the allowed deferred balance as of December 31, 2009, the midpoint of the rate year, and total MPP amortization expense are depicted in the table below.

	Description:	Amount
1	Proposed Current Amortization (7/1/09-6/30/10)	$5,514,192

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2	Amortization - Prior Balances (7/1/08-6/30/09)	$5,004,889
3	Amortization- Current Balances (7/1/08-6/30/09)	$6,000,000
4	Deferred Balance March 31, 2009	$11,026,650
5	Add Forecasted Grants (4/1/09-6/30/09) (Line 14 / 4)	$1,128,607
6	Less Prior Balances Amortization (Line 2 / 4)	-$1,251,222
7	Less Current Balances Amortization (Line 3 / 4)	-$1,500,000
8	Deferred Balance June 30, 2009 (Sum Lines 4,5,6,7)	$9,404,035
9	Pro Forma prior Balance Amortization Expense (Line 8 / 3)	$3,134,678
10	Deferred Balance at June 30, 2010 (Line 8 - Line 9)	$6,269,357
11	Deferred Balance - December 31, 2009 (Lines 8 + 10)/2	$7,836,696
12	Balance as of December 31, 2009 Per Company	$10,382,323
13	Adjustment to Deferred MPP Balance (Line 11 - Line 12)	-$2,545,627
14	Allowed Current Amortization (7/1/09-6/30/10)	$4,514,429
15	Allowed Pro forma Amortization Expense (Lines 9 + 14)	$7,649,107
16	Total Pro Forma Amortization Expense Per Company	$10,852,336
17	Expense Adjustment (Line 15 - Line 16)	-$3,203,229

Schedules B-6 and C-8, Responses to Interrogatories GA-3 Attachment, p. 2, GA-314, GA-351 and OCC- 217.

As detailed in the table above, the Department calculated a total allowed pro forma MPP amortization expense of $7,649,107; the sum of $3,134,678, the pro forma amortization expense for prior deferred balance, and $4,514,429, the pro forma current amortization expense. This amount is a $3,203,229 decrease to the total pro forma MPP amortization request of $10,852,336, which is $3,355,782 less than the test year amount of $11,004,899.

4. Depreciation Expense

Based on the Department's denial of waiver of the requirement to file a Depreciation Study, the Company

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conducted a study to determine the appropriate level of depreciation expense in the rate year. Reply Brief, p. 82; Tr. 4/15/09, p. 924. The Company hired Mr. Earl Robinson of AUS Consultants to conduct this study. Mr. Robinson recommended an increase to the Company's composite annual depreciation rate from 2.76% to 3.16%. Robinson PFT, p. 2. Using the study results, the Company is requesting a rate year level of depreciation expense of $19,375,781, an increase of $2,847,403 from the test year amount. Revised Response to Interrogatory GA-2 Corrected, Attachment 2 - Supporting Schedules.

During the hearing and in its Brief, OCC raised concerns regarding the data surrounding plastic mains and services used in the Depreciation Study. Tr. 4/15/09, pp. 994-999; Brief, pp. 162-165. OCC recommended that an amount of depreciation expense $550,000 above the test year level be allowed based on the current composite annual depreciation rate of 2.76% and the adjusted utility plant additions. The Department shares the OCC's concerns regarding the plastic mains and services and also with other aspects of the Depreciation Study. Namely, that the study did not include a review and check of the equipment in each account to verify that the equipment was in the proper account. It was for this kind of verification that the Department required the Company to include a study in its rate case filing.

However, the Department does not find it appropriate to ignore the results of the filed Depreciation Study as recommended by the OCC. The filed study includes additional years of data and, while serious concerns were raised regarding the data used for plastic mains and services and as specified in Section II.C.1. Pro Forma Plant Additions and Retirements, the Department finds it better to address these concerns and utilize the study with modifications. In addition, the filed study results are consistent with the underlying historical data analyzed and used by Mr. Robinson as a basis for his recommendations. For Account 376.20, Distribution Mains - Plastic, the Company is proposing to reduce the ASL to 50 years from 60 years. Depreciation Study, Section 2, p. 20. The Department believes it premature to reduce the ASL from the prior Depreciation Study given the relatively young life of the account (oldest vintages less than 45 years old), lack of retirements (roughly 3% of historical additions) and concerns with some of the data used in the study for this account. Mr. Robinson conceded that some of the data in the account must have been related to steel distribution mains. Depreciation Study, Section 4, p. 19 and Section 6, p. 17; Tr. 5/7/09, pp. 2241-2247. Given the lack of data and the concerns with the data, there is insufficient indication since the prior study to justify changing the ASL on this account. Therefore, relative to the proposed life on this account, the Department will increase the ASL and the remaining life (RL) ten years to 60 years and 48.4 years, respectively.

Based on this change to the RL, the depreciation rate on Account 376.2 is reduced to 2.01% from 2.53% and the depreciation on Account 376, Overall Mains Account, is reduced to 2.07% from 2.39%. This results in a reduction to the depreciation expense of $836,989. In addition, adjustments to depreciation expense detailed in Section II.C.1. Pro Forma Plant Additions and Retirements, and to plant detailed in Section II.C.2. Operations and Capital Expenditures, change the amount of depreciation expense and to plant being depreciated. Taking these adjustments into consideration along with the RL change for Account 376.2 results in a total adjustment to depreciation expense of $1,697,146.

5. DPUC Assessment Costs

Southern proposed to recover in the rate year an estimated Department assessment cost of $1,137,619. The Company noted that its pro forma estimate is based on the current year assessment as shown on the Department Invoice No. 09-084 dated September 5, 2008. The Company's proposal is $39,166 more than the test year amount of $1,098,453. Schedule C-3.11. The Company stated that its rate year's request is based on the fact that the most recent intrastate revenue from all regulated public utilities resulted in an increase to its allocation; therefore, resulting in an increase to the Company's Department assessment costs. RRP PFT, p. 29.

OCC stated that the Company failed to adjust its rate

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year proposal for $74,862, which is the prior year credit adjustment to the 2008 billed Department assessment of $1,153,895. Further, the Company received such credits over the last four years. OCC concluded that the credit represents a known and measurable amount based on the information shown on the Department's invoice. Brief, pp. 144-146.

The Department agrees with OCC's recommendation to reduce the Department assessment by $74,862. The Department believes that due to retirements, government's cost cutting and furloughs, the Department assessment costs should be lower. Therefore, the Department disallows $74,862 of the proposed assessment cost and allows $1,062,757.

6. Inflation Adjustment

The Department typically allows utilities to apply a general inflation factor to O&M expenses not specifically adjusted elsewhere. Without an inflation adjustment, the Company would not be made whole for increases in its O&M expenses not adjusted for elsewhere. In the Application, the Company used a 4.4578% composite inflation factor to adjust a pool of unadjusted expenses having a balance of $8,992,802 to produce an inflation expense of $400,881. The Company excluded fixed and contractual expenses as well as nonrecurring items from this pool of O&M expenses. Responses to Interrogatories GA-67 and GA-68. Mechanically, the Company calculated the inflation adjustment correctly; however, the inputs are subjective in nature and require revisions.

The Company developed the initial 4.4578% composite inflation factor by using the quarterly Gross Domestic Price Deflator (GDP Deflator), in the range of 1.8% to 2.7%, as published in the November 10, 2008, Blue Chip Economic Indicators/Financial Forecasts. Schedule WPC-3.38. Southern's composite inflation factor reflects the adjustment from the midpoint of the test year that represents two quarters, plus the length of the lag period, which represents four quarters plus an adjustment to the midpoint of the rate year that represents two more quarters. Response to Interrogatory GA-358.

The Department examined the group of accounts to which the Company applied the inflation adjustment. Some of the accounts have already been adjusted for known and measurable changes in the form of maintenance, labor costs and market indices. Response to Interrogatory GA-69. The Department's analysis centered on what was included in each individual account, whether the expenses were adjusted elsewhere in the Application, and the probability that inflation in the general economy would affect that account. For example, Account 885, Maintenance Supervision and Engineering, primarily relates to supervisors and engineers salaries and benefits, which Southern has already escalated. The same is true of Account 840.0; Operations Supervision & Expenses, Account 841.0; Other Labor & Expenses, Account 870.0, Operations Supervision & Engineering, Account 901.0; Supervision, all of which mostly include salaries and benefits; and Account 932; Maintenance of General Plant, which relates to labor, benefits, contractors and fleet charges. Employee Pensions and Benefits, Account 926, includes costs that relate directly to the Supplemental Employee Retirement Plan. Expenses relating to the Company's various retirement plans are specifically adjusted in their respective accounts. Tr. 4/9/2009, pp. 290-292.

The following accounts and dollar amounts should be excluded from the base of expenses not adjusted elsewhere:

Account and Title	Dollar Amount
840.0 Operation Supervision & Expenses	$ 74,464
841.0 Other Labor & Expenses	2,122
870.0 Operation Supervision & Engineering	112,126

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885.0 Maintenance Supervision & Engineering	179,609
901.0 Supervision	28,523
926.0 Employee Pensions & Benefits	786,630
932.0 Maintenance of General Plant	33,200
Total	$1,216,674

The Company stated that the amount specifically adjusted for Account 923.0, Outside Services Employed, was understated due to a miss-referencing of certain Schedule C test year amounts. This should have been $7,251,007, with the resulting unadjusted amount subject to inflation of $19,607. This represents an adjustment of $931,454 ($951,061 - $19,607) to the amount subject to the inflation adjustment included in the Application for Account 923.0, Outside Services Employed. Southern provided an exhibit reflecting a reallocation of the adjustment of $931,454 among many of the various other accounts included in its inflation adjustment. Late Filed Exhibit No. 42.

The Department believes this reallocation is erroneous. The fact that Outside legal expenses were specifically adjusted elsewhere in the Application should not impact the amounts specifically adjusted for advertising, rent or any other expense presented in the inflation calculation. The $931,454 adjustment should instead be excluded from the base of expenses not adjusted elsewhere. Subtracting $2,148,128 ($1,216,674 + $931,454) from the Company's base of $8,992,802 produces $6,844,674 in O&M expenses, which are not adjusted elsewhere and should be subject to an inflation adjustment.

As part of its updates and corrections to its Application, the Company indicated that it used the most recently published Blue Chip Economic Indicators/Financial Forecasts GDP Deflator values to update its inflation expense calculation. Using the most recent available data, the Company calculated an updated composite inflation factor of 3.4843%. WPC-3.38 Updated. This update reduced the Company's originally filed inflation expense by $87,546, for a revised inflation expense of $313,335. Response to Interrogatory GA-2, Attachment 1. Applying the updated composite inflation factor of 3.4843% to the Department adjusted O&M expense base of $6,844,674 produces an allowed inflation expense for the Company of $238,489 (3.4843% x $6,844,674). The allowed inflation expense represents a reduction of $74,846 from the Company's proposed inflation expense of $313,335.

7. Speedpay Transaction Fees/KUBRA

The Company initially proposed a pro forma adjustment of $692,390 to the test year payment service transaction fees of $69,551 for a rate year amount of $761,941. Southern's proposed adjustment to payment service transaction fees is comprised of two components: the recovery of a deferred account projected to the beginning of the rate year, and the projection of an ongoing annual payment service transaction fees expense during the rate year. The first component reflects the deferred balance of $912,799 as of June 30, 2008 plus a projection of $457,867 for the fees up to the midpoint of the rate year for a total proposed balance of $1,370,665. The Company proposed an amortization period of four years for an annual recovery amount of $342,666. The second component is based on a four-year average and reflects the expected pro forma annual expense of $419,274. This amount consists of $337,926 and $81,348 for Kubra transaction fees and credit card bank fees, respectively. The total transaction fees proposed for the rate year equals $761,941, which represents an amortization charge for the deferred balances of $342,666 plus annual ongoing expenses of $419,274. Schedules C-3.9 and WPC-3.9; Operation and Customer Relations PFT, pp. 23 and 24; Response to Interrogatory OCC-91. The Company claimed only the transaction fees were included in the test year's expenses and that the bank fees were rolled into a deferred account for pro forma amortization. Tr. 04/08/09, pp. 133-136.

In its revised filing, the Company proposed a pro forma

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adjustment of $597,343 to the test year payment service transaction fees of $69,551 for a rate year amount of $666,894. Southern proposed an accrued deferred credit card bank fees balance as of March 31, 2009 of $1,075,776 and forecasted bank fees of $67,000 from April 1, 2009 to July 1, 2009, for a total deferred balance to be amortized over four years of $1,142,776. Thus, the revised annual recovery of the deferred amount is $285,694 ($1,142,776 / 4). The Company stated that the monthly average transactions were approximately 12,000 for the latest 12 months April 1, 2008 to March 31, 2009. The $67,000 proposed as the forecasted deferred bank fees balance for the three months April 1, 2009 to July 1, 2009 was determined by escalating $55,800 (12,000 x $1.55 x 3) by 20%. Also, the Company stated that the actual Kubra transaction fees for the last 12 months are approximately $94,300. The Company used the same 20% escalation factor to derive the proposed rate year's Kubra transaction fees of $113,200 ($94,300 x 120%) and proposed annual bank credit card fees of $268,000 (12,000 x $1.55 x 12 x 120%). Response to Interrogatory OCC-91, Supplemental Attachment; Late Filed Exhibit No. 40; Response to Interrogatory GA-2, Corrected Attachment 2, p. 30. Southern proposed to include in rate base $1,199,665 as the unamortized deferred balance for credit card bank fees. Schedule B-6.0. The Company did not adjust the credit card bank fees deferred balance in rate base despite the revisions to both the accrued and forecasted deferred amounts in its updated filing.

OCC disagrees with the Company's proposal to escalate costs by 20%. This proposal is not supported and unjustified. OCC recommended reducing the Company's revised pro forma expenses and fees by $66,500. Brief, pp. 148-151.

The Department finds that the Company did not provide sufficient evidence to support the higher bank fees or larger customer usage of Kubra services to justify increasing charges beyond that related to the monthly average of 12,000 transactions. Thus, the Department concluded that the proposed 20% escalation figure is unsupported. The Department agrees with OCC that the actual Kubra transaction and credit card bank fee charges, based on the most recent 12 months ending March 31, 2009 data are more appropriate proxies for determining the rate year expenses.

In response to inquiry in the instant proceeding, Southern agreed that bank credit card fee deferrals should not be forecasted to the midpoint of the rate year. Thus, Southern changed the end date for the forecasted deferred bank fees to July 1, 2009 instead of December 31, 2009. See Tr. 04/13/2009, pp. 535-538 and Late Filed Exhibit No. 40 Attachment. This change in forecast ending date was to remove the forecasted deferred expenses for the first six months of the rate year originally included in the deferred balances. The Company should not be forecasting deferred expenses to the midpoint of the rate year while simultaneously also proposing an additional recovery of an ongoing expenditure for the 12 months in the rate year.

The Department allows the recovery in rates of the Company's proposed deferred balance of $1,131,576 ($1,075,776 + $55,800). For the rate year, the Department allows total transaction fees of $600,394, which is composed of $94,300 for the pro forma Kubra transaction fees and $223,200 for the pro forma credit card bank fees and $282,894 ($1,131,576 / 4) for the annual amortization expense of the deferred balance as of July 1, 2009. The Department allowed amount represents a $66,547 ($666,941 - $600,394) reduction to Southern's proposed rate year payment service transaction fees expenses of $666,941. Also, the Department will allow the deferred balance of $990,129 to be included in rate base for customer electronic checks and credit cards. The deferred balance allowed in rate base is the deferred balance of $1,131,576 less half year amortization of $141,447 ($282,894 / 2). Thus, rate base will be reduced by $209,536 ($1,199,332 - $990,129). The Department's analysis, which is in concert with OCC recommendation, essentially removes the unsupported 20% escalation factor embedded in the Company's forecast for deferred and pro forma expenses. Also, the amount allowed in rate base was updated to reflect the most current deferred balance as of July 1, 2009.

The Department accepts that the cost of KUBRA and related bank fees are ratepayer responsibilities and will

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allow such costs in rates in the instant proceeding. Nevertheless, should circumstances surrounding these services or costs changed materially, the Department will review the allowance of those costs in future proceedings. Therefore, in future rate cases, the Company must provide a detailed cost/benefit analysis and justify why these service costs should be socialized and included in rates rather than being charged directly to those customers using the services.

8. Insurance Expense-Self-Insured Claims

Southern proposed an insurance expense of $1,127,533 for the rate year. This amount is $345,102 higher than test year actual expenses of $664,150. The major contributor to the insurance cost increase is the proposed increase in self-insured claims of $300,622 (pro forma expense of $316,632 minus the test tear expense of $16,010). Schedule C-3.34. The Company testified that the only program that was not renewed in 2008 was fiduciary. The pro forma insurance expense was developed using actual 2008 insurance premiums. Southern stated that the test year levels were adjusted by an inflation factor after policy expiration dates had occurred. The Company stated that the self-insurance claims amount was based on a five-year historical average of 2003 through 2007 data. Schedule WPC-3.34b; RRP PFT, pp. 42 and 43. Southern's projected self-insured claims expense of $316,632 is based on a five-year average of two components; the actual claims paid and the adjustments made to the reserve balance during each period. Late Filed Exhibit No. 49. The Company agreed that the test year level of self-insured claims of $16,010 was an anomaly. The reason the test year self-insured claim amount was significantly less that the pro forma five-year average was that there was a refund from the insurance company regarding a claim that the Southern paid over and above the self-insured retention. The Company stated that self-insured claims can be large in one year and very little the next. Tr. 04/08/09, p. 137.

OCC recommended $232,778 as the self-insured claims expense to be allowed in rates. This amount is the five-year average of actual claims paid by the Company from 2004 to 2008. This is a reduction of $83,854 to the projected amount of $316,632 included in the Company's filing for self-insurance claims. OCC asserted that its recommended amount is a reasonable expense level as it is based on actual claims that had been paid by the Company and not annual changes, both upward and downward, to the self-insurance reserve. The Company's test year level of $894,668 is adequate for injuries and damages reserve balance. OCC recommended that injuries and damages reserve balance in rate base be reduced by $29,943. Brief, pp. 129-131.

The Department must exclude extraordinary or non-recurring items in its calculation of prospective expenses for the rate year and beyond. With this in mind, the Department agrees with OCC that a better guide for determining future expenses is using actual historical expenses paid over a recent period of time. It is Department's opinion that the reserve accounts contain accrued estimates of potential obligations. The reserve accounts are credited and the expense accounts are charged when the actual expenses are incurred. Ratepayers should not be paying for funds set aside in reserved accounts. Therefore, the Department disallows $83,854 of self-insurance costs ($316,632 less $232,778) and allows a self-insurance expense of $232,778, based on the five-year average of actual claims paid from 2004 to 2008.

9. Allowed Bad Debt Rate

The table below summarizes the annual non-hardship revenues and related bad debt expenses and the calculation of the bad debt expense rates beginning in 2006:

Year Ending December	Non-Hardship Revenues	Non-Hardship Bad Debt Expenses	Percentage: Expenses Vs. Revenues
2006	$361,407,122	$11,033,860	3.0530%

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2007	$362,982,078	$ 9,173,098	2.2517%
2008	$383,982,078	$ 7,613,693	1.9856%

Late Filed Exhibit No. 8; Response to Interrogatory GA-2 Supplement and Corrected, pp. 12 and 24; Response to Interrogatory GA-281, Attachment 1.

Below is a summary of the Company's allowance for doubtful accounts, total uncollectible expense and hardship uncollectible expense amounts allowed in base rates beginning in 2006:

Year Ending December:	Allowance for Doubtful Accounts	Total Uncollectible Expenses	Hardship Expenses Allowed in Base Rates in the Total
2006	$13,793,421	$13,783,594	$2,749,734
2007	$10,202,890	$10,922,832	$2,749,734
2008	$ 7,239,555	$10,360,078	$2,749,734

Responses to Interrogatories GA-414 and OCC-6 Attachments 1 and 2; Late Filed Exhibit No.8 Supplement.

The Department rejects the Company's revised 2.74% uncollectible rate for the rate year because it does not adequately reflect Southern's non-hardship expenditures since the 2005 Decision. The Company's calculation is misleading and does not account for the noticeable decreases in non-hardship A/R and expenses since the 2005 Decision. Somewhat disconcerting is the fact that the Company estimated non-hardship gross write-off amounts of $14,234,400 and $12,994,078 in 2007 and 2008, respectively, when the related non-hardship receivables were $21,576,180 and $20,135,179, respectively. As the non-hardship A/R continues to decline from the high 2005 level, the Company's forecasts of gross write-offs of non-hardship residential customer accounts were increasing.

In the 2005 Decision, the Company calculated a 2.75% uncollectible expense ratio based on the average of the percentages of the net write-offs to firm revenue for the five-year period 2000 to 2004. The 2004's ratio used to calculate the five-year average was 2.78%. See, Response to Interrogatory GA-123 Revised referenced in the 2005 Decision, p. 7. In the instant case, the Company similarly revised its proposed uncollectible percentage upward from 2.26% to 2.74% and again changed the ratio for 2004, this time, from 1.69% as originally reported to 1.74%. The 2004's gross write-off, net write-off and net write-off percentage provided in the instant case are not consistent with the information provided by the Company during discovery for the 2005 Decision. The Department found the Company's calculation of the proposed 2.74% bad debt rate and the use of write-off amounts for its calculation in the instant case to be unreliable.

Finally, the Department believes that using the typical three, four or five year average to calculate the rate year's bad debt rate ignores the clear downward trends in non-hardship receivables and expense and the steep declines in natural gas prices. Using the averages of percentages of non-hardship write-offs or of expenses to calculate the bad debt rate and expenses ignores recent data. The Company testified that it hopes that the credit collection efforts would lower uncollectible expenses in the long run. Tr. 4/39/09, p. 352. The Department believes those efforts are already having a positive effects on non-hardship portion of the uncollectible expenses. And the additional collection expenditures being approved in the instant case would further help improve those results. The Department determines that prior period uncollectible rates are significantly higher because the Company's calculations include embedded

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natural gas commodity costs that are higher than those projected for the rate year. Gas cost is approximately two-thirds of the Company's total revenue requirement.

Based on the review of the Company's non-hardship A/R reports, the amounts of provisions made for uncollectible accounts and the analysis of the actual non-hardship expenses since the 2005 Decision, the Department believes that the 1.9856% bad debt expense rate in 2008 better represents uncollectible rate for the rate year. This rate fully reflects the improvements that had been made in the non-hardship A/R balances and uncollectible expenses since the 2005 Decision. The Company's proposed non-hardship rate of 2.74% failed to incorporate these results even though 2008 epitomizes the current economic downturn and commodity gas prices were at a historical highs both non-hardship A/R and expenses declined from their 2007 levels. Currently, commodity gas costs are at historical lows. The allowed bad debt rate for the rate year will be 1.9856%.

10. Non-Hardship Net Write-offs

Southern originally proposed $9,337,190 for the rate year in non-hardship uncollectible expense, which is an increase of $2,666,372 over the test year amount of $6,570,818. The originally proposed amount was a product of the initially proposed bad debt rate of 2.26% and the non-hardship revenue of $409,353.992. The 2.26% was the average of four-year percentages of net non-hardship write-offs to the non-hardship revenues for 2004 to 2007. RRP PFT, p. 14; Schedules C-3.5 and WPC-3.5. The Company stated that as a result of the economic conditions and the uncertainty of the energy markets, much of its bad debt relates to its total revenue. As gas prices are volatile, so is its bad debt expense. The Company considered its proposal to use the average of four years bad debt rates fair because the lower percentages in 2004 and 2005 will help smooth the higher percentages in 2006 and 2007. Tr. 4/9/09, pp. 357 and 358.

The Company subsequently revised and increased the rate year's non-hardship uncollectible expense request to $9,545,670, a $2,974,852 increase over the test year amount of $6,570,818. The new proposed non-hardship expense was calculated by multiplying the revised uncollectible expense rate of 2.74% by the updated non-hardship revenue of $348,490,384 ($384,402,246 - $35,911,862). This amount was determined by subtracting $35,911,862, which is the proposed hardship revenue, from $384,402,246, which is the total pro forma revenue at present rates. The new bad debt rate of 2.74% was also based on the average of four-year percentages of net non-hardship write-offs to the non-hardship revenues for 2004 to 2007. The Company revised and increased bad debt rates in 2004, 2006 and 2007 resulting in the updated net write-off percentage of 2.74% versus the originally proposed rate of 2.26%. Response to Interrogatory GA-2 Corrected, Attachment 2, pp. 27 and 28.

The Company currently writes off a customer's account to uncollectible expense six months after it is final. The Company proposed an additional non-hardship expense of $493,250 to accelerate the amortization of write-offs from six months to three months. This proposal would result in a one-time estimated expense of $1,973,000 based on a four-year average of non-hardship net write-offs for the months of January, February and March of 2005, 2006, 2007, and 2008. The months of January, February and March represent the 91-180 day old category from July 1st when new rates are expected to be in place. The Company proposed to amortize this amount over four years for an annual expense of $493,250 ($1,973,000 / 4). The primary reason for this proposal is to improve the entire collection cycle on final accounts. As debt grows older, collection becomes increasingly more difficult. By accelerating the write-off cycle, the Company can send the delinquent accounts to collection agencies sooner, thereby, beginning the collection cycle sooner than would otherwise be the case. Moreover, Southern stated that the proposed change will align its practice with its sister company CNG. Southern also testified that regardless of the impact on the past balances in A/R there has to be a one time charge for the conversion from six to three month write-offs of non-hardship final amounts in the A/R balances. RRP PFT, pp 23 and 24, Schedules C-3.17 and WPC-3.17; Tr. 04/08/09, pp. 149-152.

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In compliance with Order Nos. 18 and 19 in the 2005 Decision, the Company filed reports regarding the progress it achieved on collections efforts and a collection activities report. The report includes an A/R aging detail, number of customers shut-off due to non-payment, number of customers reconnected, number of curb vales installed, number of meters relocated outside, and its top 50 C&I delinquent accounts for calendar years ending 2006 and 2007. The Company stated that the actions it took since the 2005 Decision are aimed at increasing collection activities and changing consumer behavior to effectively address long-term delinquency issues. Nonetheless, the Company expressed its pleasure over the significant progress achieved in its collections and the overall accounts receivables since the 2005 Decision. Southern stated that it has substantially increased its collection and field disconnection efforts.

In 2006, the Company created a new organization and reassigned personnel to execute the collection initiatives. A new director and manager were transferred into that department in February of 2006. In 2008, the Company authorized several new positions in the customer relations area that will provide further assistance in overall collection efforts. This included two new field collectors to supplement and enhance field collections and energy assistance outreach; a credit analyst to assist with the various analytical and reporting aspects of the collections area; three call center representatives to handle incoming calls, some of which are credit related. The Company stated that service disconnections nearly tripled from 3,677 in 2005 to 9,300 in 2006, and rose again to 11,851 in 2007. Dollars associated with disconnections rose from $6.6 million in 2005 to $21.3 million in 2006 and $25.2 million in 2007. The 2008 target is 13,000 disconnections at similar A/R balances as 2007. Response to Interrogatory OCC-33, Attachment 3, pp. 1 and 2.

Southern stated that it implemented the Meter Relocation Program to increase the number of meters located to the outside of buildings to improve accessibility to shut-off delinquent accounts. In 2006 and 2007, Southern spent approximately $8.2 million and installed 1,760 new services. Approximately 3,900 meters were relocated, and over 1,400 delinquent accounts were locked for non-payment, representing approximately $5.9 million in A/R. In 2008, it allocated an additional $1.5 million in capital for the program as it requires extensive coordination between operations, call center, and credit and collections teams. In 2007, Southern accelerated the mailing of disconnect notices earlier in the collection cycle from 60 days delinquent to 33 days, instituted a security deposit requirement for non-hardship residential customers who were shut-off for non-payment and reinforced the requirement that customers pay at least 75% of back bill amount owed prior to the reinstatement of service. Id, p. 3.

In 2007, the Company hired an outside firm to expand its energy assistance outreach. This vendor canvassed neighborhoods in a door-to-door effort to educate customers about energy assistance and Southern's matching payment programs. It pre-qualified them for energy assistance and referred customers to local energy assistance intake sites for possible grants. This effort proved very successful, increasing its hardship count from 14,672 in 2006 to 18,835 in 2007, a 28% increase. Southern plans to hire this firm again in 2008 to assist in similar outreach efforts. In late 2007, the Company retained an outside firm on a trial basis to expand its automated dialing/voice messaging efforts on delinquent accounts. The application ran for 60 days, contacting thousands of accounts during that time in an effort to remind customers of delinquent balances and motivate payments. The pilot was recently closed and an evaluation of the effectiveness of the program will be conducted to determine if the application would be cost beneficial to use on a going forward basis. Id, pp. 4 and 5.

Since 2005, the Company stated that, its disconnection, meter relocation and overall collection efforts have produced extremely positive results in its A/R as depicted in the tables below. In 2007, the Company active accounts receivable declined by over $14.3 million or 18% compared to 2005 and the overall A/R decreased by approximately $9 million, or 10%. Southern stated that its efforts were very effective in reducing the residential non-hardship balances, which continues to be an

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area of emphasis for its collection efforts. The total A/R balances for residential non-hardship over 90-day delinquent was reduced by nearly $7.7 million or 60% in 2007 compared to 2005. The overall residential hardship category increased by 8% due mainly to the success of energy outreach efforts and to the moratorium and service protections afforded the hardship group. The Company believes that its collection efforts have proved successful for the two years following the 2005 Decision and that these efforts will continue to stabilize its A/R and uncollectible expense over the long term. Southern stated it will continue to implement these collection strategies and work to identify new initiatives in an effort to sustain progress. Nevertheless, the Company noted that the A/R balance is a snapshot in time and that the change during the course of a year is due to several factors including fluctuations in billed volumes and gas commodity prices. OCC-33 Attachment 3, pp. 6-9. In response to the Department's inquiry, the Company provided a worksheet that shows that 2008 A/R is approximately 20% less than 2005 level. Response to Interrogatory OCC-33, Attachment 3 Supplement.

According to OCC, the uncollectible expense levels varied between the years 2003 and 2008. The aggressive collection efforts undertaken by the Company were reflected primarily in the years 2006, 2007 and 2008. OCC stated that 2006's net non-hardship write-off reflects the most aggressive approach with the highest gross write-offs. The gross write-offs and the net write-offs declined in 2007 and again in 2008. The decline in net write-offs reflected the aggressive collection efforts of the Company. OCC declared that the decline in outstanding A/R, as reported in response to Late Filed Exhibit No. 26 Attachment, reflects the improved A/R position. The Company's proposed non-hardship uncollectible expense ignores the progress achieved and assumes that going forward uncollectibles will continue at approximately the 2008 rate. Brief, pp. 112-117.

OCC recommended that the uncollectible expense be based on 2.49%, the five-year average of net write-offs from 2003 through 2008 excluding the 2006 amount. This would smooth out the higher uncollectible percentages and would reflect the changes to collection procedures. Also, OCC stated that this recommendation is consistent with that it made for the sister company CNG. The recommended 2.49% bad debt rate would reduce the Company's proposed non-hardship expense by $870,919. As an alternative, OCC recommended the four-year average of 2.33%, which is based on uncollectible percentages for 2004 though 2008 excluding 2006. Brief, pp. 112-117. Finally, OCC asserted that the Company's claim that its proposal to change from writing off final accounts from six months to three months will improve things in the long run contradicts the Company's other claim that this change in write-off policy will not affect future amounts of write-offs. Implementing this change will, in fact, have an impact on the level of write-offs. Brief, p. 116.

The Department thoroughly reviewed the Company's testimonies and exhibits in support of the proposed non-hardship expenses for the rate year. A review of the Company's aging A/R report indicated that non-hardship receivables had declined noticeable since the 2005 Decision. The annual balances of non-hardship receivables for residential active accounts and the annual amounts of gross and net non-hardship write-offs are illustrated by the table below:

12-Months Ending	Non-Hardship A/R	Gross Write-Offs	Net Write-Offs
December 2005	$37,116,827	$8,688,574	$5,969,305
December 2006	$26,633,107	$15,212,469	$12,140,458
December 2007	$21,576,180	$14,234,400	$11,776,750
December 2008	$20,135,179	$12,994,078	$10,560,623

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Responses to Interrogatories OCC-33, Attachments 1-3; OCC-33 Supplement Att., and GA-281 Att. 1; Late Filed Exhibit No. 26 Att., pp. 12 and 24.

The Company testified that the higher write-offs in 2006 and 2007 are the expected results of its continued aggressive credit and collection efforts. Specifically, as it began to aggressively pursue delinquent customers, particularly those with high balances, older arrearages, for overdue payments and to terminate services for non-payments. The goal is to control A/R and A/R reserve requirements and finally to reduce uncollectible expenses in the long run. The Company stated that this action resulted in disconnection of services to approximately 3,700 accounts in 2005, 9,300 in 2006, 11,850 in 2007 and 13,400 in 2008, and a projected 14,500 accounts in 2009. Southern stated that accounts become final for other reasons beside disconnections for non-payment. As a result of the increased disconnection actions, more accounts went to inactive status and finally to write-off. The Company stated that in 2007 final accounts were $7.6 million more than in 2006, and that net write-offs increased by about $4 million. In 2008, there were $8.6 million more final accounts than in 2006, which resulted in additional $4.0 million net write-offs. The Company stated that the current economic crisis would most likely increase its uncollectibles in the rate year and that the proposed adjustment to uncollectible expenses is inadequate. Response to Interrogatory GA-282, pp. 1 and 2; Tr. 04/09/09, pp. 350-357.

There is nothing in the record in this proceeding to support the claim that the increases in the numbers of disconnected accounts are related to non-hardship A/R or expenses. However, the record is clear that the non-hardship A/R and expenses declined significantly from their 2005 levels. As the tables and summaries above show, there is no correlation between the number of disconnected accounts and the amounts of non-hardship account A/R and expenses. The Department will allow a bad debt rate of 1.9856% which is applied to the proposed non-hardship revenue of $348,490,384 to determine the allowed non-hardship uncollectible expense of $6,919,510 ($348,490,384 x 1.9856%). This amount resulted in a $2,626,160 decrease to the Company's proposed non-hardship expense for the rate year, which is a $348,692 increase over the test year amounts.

The Department disagrees with the Company's position that the change from six months to three months to write-off delinquent final accounts would create a one time charge. The Company would not request this adjustment if the proposed three month write-off of final non-hardship accounts had been in place in 2005, 2006, 2007, and 2008. Moreover, the Company's financial statements, (e.g., retained earnings and balance sheet, and related regulatory rate items such as allowance for working capital and the lead-lag study) submitted with the instant rate Application would also be different. As of December 2008, the balance in final A/R was $18,151,558. Response to Interrogatory OCC-33 Supplement Attachment. The Department agrees that an earlier write-off of any portion of these final amounts, hardship or non-hardship, would improve collection cycle as delinquent final A/R would enter the collection process sooner. However, such change does not create any charge to income statement for the estimated amounts that should have been written off in past if the new three months write-off had been in place. And to the extent that the income statement is affected by such change, the Company's balance sheet and retained would similarly be impacted. The Company did not explain how a one-time charge to the income statement would affect its other financial statements.

The Department believes such analysis on the impact on other financial statements would highlight the affects such a one-time charge would have on the cost of capital and on rate base items. Also, consistency with an affiliate's approach to estimating uncollectible write-off is neither GAAP nor a mandated regulatory standard. The change to three months for writing off final A/R should be done prospectively and would be reflected in A/R balances and net write-off amounts subsequent to the beginning of the rate year. Base on the aforementioned, the Department disallows the recovery of this estimated one time write-off expense of $1,973,000 from accelerating the non-hardship write-offs from six months to three months after such accounts become final. Thus,

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the Company's proposed amortization expenses related to this one-time charge is disallowed and the rate year's expenses are reduced by $493,250.

Furthermore, due to SFA, the Department increases non-hardship uncollectible expense by $84,608, which is the SFA's additional revenue of $4,261,093 times the allowed uncollectible rate of 1.9856%. Thus, the total decrease to the proposed uncollectible expense is $3,019,353 ($2,610,711 + $493,250 - $84,608) and the Department allows $6,526,317 ($9,545,670 - $3,019,353).

11. Collection Activities - Outbound Dialing Vendor

Southern testified that in September 2007 it selected iQor to perform collection services in place its former vendor, OSI. The expenses for the test year were $175,113 and $705,024 for OSI and iQor, respectively, for a total of $880,137. Southern proposed $1,123,763 for the rate year for iQor's active collection dialing expenses or $243,626 above test year amount. Schedule C-3.26; RRP PFT, pp. 26 and 27.

In addition to active collection services being provided by iQor, Southern stated that in January 2008 it contracted with a "state of the art" dialing vendor, Varolli, to improve its dialing performance and contact rates. Southern is requesting $240,000 for the rate year for Varolli's third-party dialing collection efforts based on an estimated expense of $20,000 per month. This amount is $185,737 above the test year expense of $54,263. Southern stated that Varolli offers its customer the ability to pay off their delinquent balance through its Interactive Voice Response (IVR) system, resulting in a more efficient means of handling delinquencies. The Company claimed that these vendors are not directed at the same customer delinquency groups. Varolli is better suited for early stage delinquencies and its outbound calls are directed to customers who are 30 to 60 days in arrears. However, iQor is better suited for the higher balance, older accounts in the 60 to 120 or more days in arrears. These groups require an agent to negotiate payment arrangement with the customers. Schedule C-3.25; RRP PFT, pp. 27-29; Response to Interrogatory OCC-43.

OCC argued that the five actual bills received by Southern from Varolli totaled $74,805 for the five months ending February 2009 and averaged only $14,961 per month. OCC recommended reducing the Company's request of $20,000 per month to $14,961 per month for a rate year expense of $179,532 ($14,961 x 12). This will reduce the Company's proposed expenditure for Varolli by $60,468. Brief, p. 123.

The Department acknowledges OCC's calculation based on Varolli actual billings for the five months ending February 2009 does not show a monthly average billing of $20,000. However, the Department notes that this service is a relatively new tool for Southern to use to reduce its uncollectible expenses and outstanding receivable balances. If the "self-cure" approach or feature of Varolli's outbound collections calls continue to help mitigate additional new A/Rs from going into default, this a goal for which the Department will encourage the Company to strive. Therefore, the Department will allow $200,000 for outbound dialing service at this time until the Department can review its effectiveness in the Company's next rate filing. The allowed amount is a $40,000 reduction from the Company's proposed outbound dialing service expense of $240,000.

12. Payroll Expense - Excluding Executive

In the instant case, Southern originally requested a rate year payroll expense of $20,889,775 compared to the test year amount of $19,989,756 resulting in a pro forma adjustment of $900,019. The Company stated that the additional payroll request is only for amounts charged to expense and not to capitalized payroll. Schedule C-3.3; RRP PFT, pp. 8-10. In its revised filing, the Company proposed a reduction of $381,867 ($20,889,775 - $20,507,908) to the proposed rate year payroll expense. This revision resulted in a pro forma adjustment of $518,151. Southern's payroll revisions included an increase of $5,892 to vacancies payroll, the reduction of incentive compensation by $196,488 and the removal of $175,000 of restricted stocks. The Company also reduced stock option expense by $109, 000.

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Responses to Interrogatories GA-2 Corrected, pp. 22-25 and OCC-270; Late Filed Exhibit No. 21.

a. Payroll Expense Percentage

Southern proposed a payroll expense ratio of 74.6% for the rate year. The ratio was calculated and based on the average of the percentages of expensed payroll to total payroll for the three years 2005 to 2007. Schedules C-3.3 and C-3.3f.

OCC noted that in the Company's response to Late Filed Exhibit No 20, the percentages of overtime expensed declined from 82.7% in 2004 to 68.1% in 2008. The Company calculated the same capitalization percentage for the test year and the rate year in a response to a Department inquiry. The Company is also projecting an increase to the level of payroll allocated to affiliates. OCC recommended that the test year expense ratio of 73.4% be used instead of the pro forma expense ratio of 74.6% to calculate the percentage of the total payroll amount to be expensed in the rate year. Brief, pp. 108-110.

The Department agrees with the Company that the calculation of the capitalization ratios in Response to Interrogatory GA-375 are erroneous. However, the Company failed to adequately explain the noticeable declines in the overtime expense factors from 2004 to 2008. For both the test and rate years, the Company's proposal for payroll expense included the application of the same expense ratio to all payroll categories except for stock option and inter-company payroll expenses. Schedules C-3.3 and C-3.3f. The Department believes that it is not appropriate to ignore the fact that the overtime payroll expense factor had declined to 68.1% in 2008. The Department calculated a payroll expense factor of 74.34% for the rate year that is based on the three-year average of the percentages of overtime expensed to total overtime payroll for 2006 to 2008. As a result, the expensed payroll will be reduced by $75,474 [(74.6% - 74.34%) x $25,467,684)].

b. Base Payroll

The Company initially stated that the pro forma payroll expense is based on a three-year historical average. It includes costs for 323 full time employees and officers adjusted for an annual vacancy allowance and additional resources required for four full time positions of conservation, training, customer satisfaction and marketing and sales analysts. RRP PFT, p. 8; Schedules WPC-3.3b and WPC-3.3g. The Company stated that it currently started recruiting for the training analyst. The process was just started to fill the customer satisfaction analyst position. A requisition was submitted to management for approval to start the recruitment process. The Company has not started the process for the marketing and sales analyst or the conservation analyst. These requests will depend on the Company receiving approvals in the instant case for proposed decoupling and for enhanced conservation programs. The Company is still looking at the "criticality" of those positions. Tr. 04/09/09, pp. 302-304.

OCC noted that the Company's own testimonies indicated that four positions have yet to be filled and that the possibility exists that they may not be filled. OCC recommended that the pro forma job count be reduced to the test year level of 319 plus the approved training analyst position for which approval has been given. Given the state of the economy, it is not appropriate to allow the cost for additional employees when approval remains uncertain. OCC noted that the Department had removed costs of vacant positions from pro forma payroll expense in past rate cases. OCC recommended that an adjustment of $188,400 be made to remove the costs for three positions that the Company acknowledged may not be filled. Brief, pp. 103 and 104.

AG, similarly, argued that ratepayers should not be paying for employees that may never be hired. AG recommended that the Department keep the active position counts at the test year level of 319 and disallow the entire $250,000 for these four vacancy positions. Brief, pp. 3 and 4.

The Department agrees with both OCC and AG that it is doubtful the Company will fill these positions during the rate year given the uncertainty of the current economic climate. The Company has not adequately measured and failed to validate the criticality of any of these

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positions. The mere fact that the Company testified that it has received approval to start the process to recruit a training analyst itself is not a justification for including it costs in pro forma payroll expense. The Company testified that it plans to fill the position of the training analyst in the "near term." See, Tr. 04/09/09, p. 304. The Department does not agree that the future time is imminently in the rate year. The Department agrees with the AG that the Company did not justify increasing employee levels above the test year count of 319. Therefore, the Department will reduce payroll expense by $185,924. The Department determines this amount by applying the payroll expense factor of 74.34% to $250,100, the total proposed for the "additional resources required."

c. Overtime Payroll

Southern proposed a rate year total overtime payroll level of $3,533,787; which is a decrease of $3,266 from the test year amount of $3,537,053. In its calculation, the Company factored in pro forma union and non-union increases to calculate the pro forma overtime amount of $3,643,079. The three-year average of overtime hours from 2005 through 2007 was 78,373, which the Company compared to the test year overtime hours of 80,927 to derive a factor of 97% (78,373/80,927). This factor was applied to the pro forma overtime payroll to calculate the rate year amount of $3,533,787 ($3,643,079 x 97%). Schedules C-3.3 and WPC-3.3e.

In response to a Department inquiry, Southern calculated the average actual historical overtime payroll level of $3,376,029 for the three fiscal years June 30, 2005 through June 30, 2007. This amount was used to calculate the ratio of the pro forma average overtime payroll levels to the test year level, which resulted in a 95% factor. This factor was applied to the pro forma overtime payroll and resulted in $3,460,925 ($3,643,079 x 95%) for the rate year. Using the overtime dollar amounts instead of hours resulted in approximately $72,862 ($3,533,787 - $3,460,925) less than Southern proposed. Response to Interrogatory GA-377.

OCC noted that the total overtime dollars fluctuated from 2004 to 2008 and that the percentage of overtime expensed compared to the amount capitalized fluctuated even more from 2004-2008. OCC did not recommend an adjustment to the proposed overtime payroll amount but recommended that the Department utilize the test year expense ratio of 73.4% for the rate year. Brief, pp. 108-110.

The Department believes that the Company's proposal to calculate a ratio of overtime hours by comparing an average of three calendar years overtime hours to test year overtime hours is distortive. As the Company correctly stated in its response to an inquiry, overtime hours fluctuate from year to year due primarily to "winter heating seasons or other weather related conditions."See, Response to Interrogatory GA-377. Thus, comparing pro forma overtime hours, determined as an average of calendar year data, to fiscal test year levels ignores this seasonality. The Department believes the ratio calculated in the Company's response, although based on overtime payroll expenses instead of hours, compares an average based on the same 12 months periods as the fiscal test year ending June 30, 2008, thus incorporating the known seasonality effect. Consequently, the Department will reduce the rate year's overtime payroll expensed by $54,166. The Department determines this amount by applying the payroll expense factor of 74.34% to $72,862.

d. Incentive Compensation

The Department reduces incentive compensation by $202,991. See, Section II.E.13.e.ii. Employee Recognition Programs.

e. Stock Option Expense

The Company originally proposed a stock option expense of a $165,000 or $205,304 increase over the test year amount of negative $40,304. Schedule C-3.3. In its revised filing, Southern proposed a stock option expense of $56,000 for the rate year, a $100,304 increase over the test year amount. Response to Interrogatory GA-2 Corrected, Attachment 2, p. 22. Southern stated that the rate year stock option expense level assumes an

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average cost for stock option expense exclusive of any purchase premium associated with the acquisition of Energy East by Iberdrola, S.A. (Iberdrola). Although Energy East has been acquired, Southern expects an equivalent type of compensation program to be put in place by Iberdrola. Response to Interrogatory GA-227. The updated request is $109,000 ($165,000 - $56,000) less than originally proposed. Late Filed Exhibit No. 21.

OCC noted that Southern's parent company, Energy East, was acquired by Iberdrola who does not have a stock option plan. The Company assumed for the rate year that there is an Iberdrola's stock option plan and that the market would be sufficient to create an expense. There is no stock plan and the economy has not recovered sufficiently to assume that an expense of $56,000 is reasonable. Therefore, OCC recommended that the stock option expense be disallowed for ratemaking purposes. Brief, pp. 110 and 111.

The Company testified that the stock option expense for the test year was based on the value of Energy East's stock prices. Stock option expense related to executive compensation would be eliminated from expenses to be recovered in rates. Tr. 4/9/09, pp. 334 and 335. Energy East's shares are no longer publicly trade following its acquisition by Iberdrola. No evidence was provided in this proceeding to support the Company's expectation that Iberdrola would grant stock options to executives or non-executives for them to exercise during the rate year. The Department agrees with OCC and will disallow the recovery in rates of the proposed stock option expense of $56,000 included in the rate year total payroll expense.

f. Payroll Summary

The Department made the following decreases to the Company's proposed payroll expense:

Expense Percentage	$ 75,474
Base Payroll	$185,924
Overtime Payroll	$ 54,166
Incentive Compensation	$202,991
Stock Option Expense	$ 56,000
Total Payroll Adjustment	$574,555

13. Pensions

a. Qualified Pension Plans

Southern sponsors two qualified pension plans, which are for salaried employees and bargaining unit employees. These qualified plans meet certain criteria under the Internal Revenue Code. Stone and Freedman PFT, p. 6. Pension expense is accounted for under the Financial Accounting Standards Board (FASB) Statement of Financial Accounting Standards No. 87 (FAS 87). It provides the methodology for all companies to recognize employees' future retirement benefit costs as they accrue over each employee's working career. Stone and Freedman PFT, p. 8.

Southern indicated that its qualified pension expense is calculated using actuarial assumptions of expected return on plan assets, discount rate, and salary increase assumption. The expected return is a long-term projection of the probable return on pension plan assets, which is influenced by the particular asset mix and expected returns on that asset mix. The higher the assumption for future returns on plan assets results in lower pension expense. The discount rate is the rate at which projected benefits are discounted back to a present value. It is used to evaluate the present value of the pension plan liabilities. The higher discount rate equates to a lower present value of pension plan liabilities result-

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ing in lower pension expense. The salary increase assumption is the long-term assumption of salary increase for all the employees' in the pension plan. Stone and Freedman PFT, pp. 9 -16.

The assumptions for the test year cost of $455,472 are the following:

Discount rate for 2007 portion/2008 portion	5.75%/6.00%
Salary increase assumption	4.0%
Expected return on asset assumption	8.75%

Schedule WPC-3.4a.

The assumptions for the rate year cost of $1,843,608 are the following:

Discount rate for 2009 portion/2010 portion	6.00%
Salary increase assumption	4.0%
Expected return on asset assumption	8.75%

Schedule WPC-3.4a.

The Company stated that the pension plan expense is calculated on a calendar year basis, which is Southern's fiscal year. The pro forma year is from July 1, 2009 to June 30, 2010. The pro forma expense was calculated by projecting the 2008 fiscal year FAS 87 benefit obligations, assets and balance sheet to January 1, 2009 and January 1, 2010 and then a 2009 and 2010 fiscal year expense is determined. The pro forma expense is then derived by including six months of the 2009 fiscal year expense and six months of the 2010 fiscal year expense. Stone and Freedman PFT, p. 19.

Southern testified that the pro forma year pension expense is over 400% greater than the test year expense; a dramatic increase. This increase in pension expense was caused by several factors. The most significant is that Southern had realized returns significantly less than the expected return assumption of 8.75% on the fair value of assets (FVA) from January 1, 2008 through October 31, 2008, which caused an increase in expense. The calculation of Southern's qualified pension expense uses a smoothed asset value called the market related value of assets (DRVA). The method used to calculate the DRVA is such that a portion of this negative asset performance is reflected in the DRVA as of January 1, 2009 and January 1, 2010. This negative asset performance reflected in the DRVA resulted in a decrease in the expected return on assets. Further, a portion of the 2008 asset loss increases the expense as an amortized loss as of January 1, 2009 and January 1, 2010. This is because both of the qualified pension plans have an unrecognized loss amount that is outside the FAS 87 10% gain/loss corridor. Stone and Freedman PFT, p. 21.

The Company indicated that the increase in pension expense was partially offset by two actions. The first action was that Southern recommenced the amortization of its regulatory liability in the pro forma year, which is an offset of $1,327,872 to pension expense. Second, Southern increased the discount rate from 5.75% for the first half of the test year to 6.00% for the pro forma year. As the discount rate increases, the liability, which is the present value of the pension plan's obligations, decreases. Due to this decrease in the present value, the service cost and interest cost decrease. This decreases the loss amortization component of the FAS 87 expense since each of the three qualified pension plans has an unrecognized loss amount that is outside the FAS 87

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10% gain/loss corridor. Stone and Freedman PFT, pp. 21 and 22.

Southern stated that the qualified pension plan regulatory liability was established at the time of the merger between Southern and Energy East as required by the rules of purchase accounting. This regulatory liability was amortized from the time of the merger until 2002 at which time the regulatory liability was eliminated as part of the entry to record an additional minimum liability (AML). The recording of the AML was required by FAS 87 when the qualified pension plan assets were less than the plan's accumulated benefit obligation (ABO). Amortization of the regulatory liability was suspended until the asset level increased to the level of the ABO. Financial Accounting Standard 158 Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans (FAS 158) eliminated the accounting requirement to record an AML in the event that a qualified pension plan's assets were less than the plan's ABO. The amortization of the regulatory liability was scheduled to recommence as of January 1, 2007 under FAS 158 accounting. For rate case purposes, the amortization credit will commence on July 1, 2009, which is the beginning of the rate year. As such the pro forma year expense includes the amortization of the regulatory liability of $1,327,872. Stone and Freedman PFT, p. 22; Schedule C-3.4(a).

The Department is concerned about Southern's qualified pension plan expense increase. However, the Department believes this is primarily due to the turmoil in the financial markets and has little to do with Southern's overall management of its qualified pension plan. The Department notes that Southern has taken steps to mitigate the pension cost increase. The qualified plans have been amended to provide for a cash balance formula for newly-hired employees, which are for non-union employees hired after 2003, and union employees hired after 2001. Under a cash balance formula, each employee's pension amount is defined as a hypothetical account that is credited with a percentage of each employee's salary each year together with a guaranteed level of interest. This differs from the traditional formula that calculates an annual benefit based on an employee's final average earnings and years of service at retirement for non-union and union participants.

Cash balance formula plans, over the long-term, provide a more predictable and lower FAS 87 expense than the traditional plan formulas they replace. The lower and more predictable expenses under the cash balance formula are realized as the percentage of benefit obligation for newly hired employees continues to increase. Stone and Freedman PFT, pp. 23 and 24. While the Department lauds the Company's effort to mitigate pension cost increase, it also notes that the Company delayed implementation of the cash balance formula for salaried employees until two years after it had modified the union plan. This action by the Company was particularly unfortunate since the average salaried employee receives pay at a higher rate than the average union employee.

OCC asserts that the discount rate assumption should be changed to 6.25% and provides this analysis of Southern's pension assumptions:

Assumptions	2005	2006	2007	2008	2009
Discount rate	5.50%	5.75%	5.75%	6.00%	6.10%
Salary Scale	4.00%	4.00%	4.00%	4.00%	4.00%
Expected return on assets	8.75%	8.75%	8.75%	8.75%	8.75%

Brief, p. 156.

OCC believes that since the 2010 calculations are a projection, it would be prudent to use the best available assumptions. There is an upward trend in the discount rate and as such it would be consistent to assume that the

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trend would continue. Therefore, a 6.25% discount rate is consistent with the current trend. OCC takes exception to Southern's actuary that the pension assumptions must "hang together" with one another. From the above table, it appears that the discount rate is somewhat independent from the other assumptions. Further, the discount rate has changed over time while the salary scale and expected return on assets have stayed constant. OCC concludes that this means that in years 2005 through 2009 the discount rate was in consistent with the other assumptions and they did not all hang together. Brief, p. 157.

The Department agrees with OCC's analysis. The Department finds that a discount rate of 6.25% should be applied in the calculation of Southern's qualified pension plans.

OCC also took exception with the salary increase assumption of 4.0% due to inconsistency with Southern's salary cycle. The Company's pay increase cycle for executive and salaried employees is typically 18 months or longer. OCC reasons that since the 4% is a compound number, the 18-month cycle is not incorporated in the 4% assumption, and has the impact of overstating the salary scale. Southern's 18-month cycle only applies to the non-union side. Brief, p. 157.

The Department, in general, concurs with OCC's analysis of the salary increase assumption. The Department finds that a 3.50% salary assumption is justified and should be applied in the calculation of Southern's qualified pension plans.

In its brief, OCC shows the calculation for pension in the format of Schedule WPC-3.4a as follows:

Line No.	Rate Year 7/1/2009-6/30/10 Net Periodic Cost/(income)	Response to Interrogatory OCC-262	Late Filed Exhibit No. 83, Attachment 1, Scenario 1
19	Subtotal	$3,206,189	$3,016,494
20	Amortization of regulatory asset / (liability)	($1,327,872)	($1,327,872)
21	Deferred compensation interest expense	$0	$0
22	Allocation to non-regulated entities	($535,103)	($503,443)
23	Total Rate Year Cost	$1,343,214	$1,185,179

Brief, p. 161.

Consequently, OCC requested that the Department reduce Southern's qualified pension expense by $158,035 ($1,343,214 - $1,185,179).

AG also took exception to the inaccurate assumptions made by Southern relative to the salary increase assumption. Southern assumed a 4% annual salary increase in its qualified pension plan calculations. Southern wage increases, however, do not come annually but rather on an 18-month schedule. AG recommends that Southern's requested qualified pension expense of $1,843,608 (per Tower Perrins PFT, p. 4) for the rate year be reduced by approximately $500,000 to correct for an inaccurate salary increase projection. Brief, p. 5.

The Department concurs with AG and OCC's argument based on the recalculation of the salary increase assumption. These recalculations result in a decrease in the qualified pension expense of approximately $500,000 by the AG and $158,035 by OCC. In its revised filing, the Company reported qualified pension

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plan cost of $1,796,071 for the rate year. Response to Interrogatory GA-2 Corrected Attachment 2, pp. 25 and 26. The Department's calculations more closely match OCC's calculation. Decreasing the salary increase assumption from 4.0% to 3.5% and increasing the discount rate assumption change from 6.1% to 6.25%, the Department, adjusts the qualified pension plan cost downward by $189,695 to $1,606,376. See, Scenario 1 in Late Filed Exhibit No. 83 Attachment 1 and Response to Interrogatory GA-2 Corrected Attachment 2, pp 25 and 26. The Department applies the revised payroll factor of 74.34% to calculate the disallowed qualified pension plan expense of $141,019 ($189,695 x 74.34%).

b. Funding for Qualified Pension Plans

OCC notes that Southern's policy for funding the qualified pension plans is to fund only the minimum amount with some exceptions. OCC asserts that if ratepayers are being charged for pension expenses, then they are providing the cash for a pension contribution. Tr. 4/20/09, p. 1717; Brief, pp. 161 and 162. These funding decisions are made by Energy East with fiduciary input and not by Southern. Southern's actuary testified that making contributions to the plans not only reduces current expenses but reduces future expenses as well. Tr. 4/20/09, p. 1736.

The Department agrees with OCC's analysis and recommendations regarding pension contributions. Southern should pay strict attention to the allocation of ratepayer funds. The Department directs Southern to make pension contributions at a minimum level equal to what is given in rates to the extent such funding will not exceed the maximum payments allowed under the Employee Retirement Income Security Act (ERISA). If in a given year the actual amount allowed for in pension expense in rates exceeds the maximum allowed funding under ERISA requirements, then Southern will be required to contribute the ERISA maximum allowed funding in such periods which will result in reduced pension costs in the future.

c. Non-qualified Pension Plans

Southern funds six separate non-qualified pension plans. Non-qualified pension plans do not meet the qualifying criteria under the Internal Revenue Code of the United States. Towers Perrin PFT, pp. 6 and 7. These are Southern Board of Directors (BOD) Plan (Southern BOD), Southern Supplemental Executive Retirement Plan (Southern SERP), Southern Benefit Equalization Plan (Southern BEP), Southern Deferred Compensation Plan (Southern DC), Energy East Corporation Supplemental Executive Retirement Plan (EEC SERP), and Energy East Excess Plan (EEC EX). The four "Southern" plans are closed to new entrants. The "Energy East" plans do not benefit any current Southern employees. Southern pays into the Energy East plans to support benefits for Southern's President, who is an employee of Energy East. Southern is seeking a combined pro forma expense for these non-qualified plans of $611,303. Schedule C-3.4; Late Filed Exhibit No. 82. In addition, Southern is also requesting $125,583 for the amortization of a past non-qualified plan regulatory asset and $20,232 identified as deferred compensation interest expense for the rate year. Schedule WPC-3.4a; Late Filed Exhibit No. 82. This is a total expense of $757,118.

The EEC SERP and the EEC EX plans cover Energy East officers and operating company presidents with a participation date being the date of hire. Participants are eligible at age 55 with 5 years of service. The only participant included in these plans in the instant case is Southern's president, an employee of Berkshire Gas. The benefits of these plans are calculated based on final average compensation (FAC). FAC is defined as the highest consecutive three-year average of covered payout of the last five years where covered pay includes base pay plus the short-term incentive payment paid in the year. Vesting is after five years of service. The EEC SERP provides a benefit of 3% of FAC for each year of service up to 15 years and 1.2% of FAC for service in excess of 15 years to a maximum of 75%.

OCC argues that the costs included for the EEC SERP and EEC EX are entirely related to Southern's president and should be disallowed based on the current economic climate. As such, ratepayers should not be asked to fund

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this cost associated with an excessive benefit plan. Brief, p. 125.

The Department agrees with OCC that ratepayers should not fund generous benefits in these difficult economic times. The Department cites precedence in this issue where in the Decision dated October 13, 1995 in Docket No. 95-02-07PH01,Application of the Connecticut Natural Gas Corporation for a Rate Increase (CNG Decision), the Department stated, "[a]lthough the Department has allowed this in past rate cases, it is too great of an expense to be borne by ratepayers struggling under a poor economy."CNG Decision, p. 45. The Department disallows for ratemaking purposes the EEC SERP and EEC EX expense. The Department also takes exception with Southern funding the salary and pension of persons who are not employees of the Company.

The Southern BOD, Southern SERP, Southern BEP, and Southern DC Plans are all closed to new participants. The Southern BOD Plan funds benefits to former members of its BOD who no longer serve the firm. During their tenure, the members of the Southern BOD were not considered company employees. Response to Interrogatory GA-236. It is atypical for a firm to offer pension benefits to non-employees.

OCC recommended that expenses associated with the Southern BOD retirement plan be excluded from the instant case. Brief, p. 125. Southern included in its requested rates costs associated with past Southern board members who no longer provide any services to customers. Response to Interrogatory GA-236. During the period these prior board members were actually engaged by the Company providing services to ratepayers, an expense would have been recorded on Southern's books associated with the service costs accrued to the BOD Plan. Southern's position via their actuarial consultant is that customers have not yet fully reimbursed Southern for the benefits provided to the prior plan participants. Towers Perrin PFT, p. 25.

The Department determined that during the past time period that Southern's BOD members provided services to ratepayers, a cost would have been accrued on Southern's books that would have paid for projected future provisions of the benefits under the Southern BOD Plan. Therefore, the Department disallows all expense associated with the Southern BOD Plan. Based on the finding that the non-qualified pension plans should be disallowed, the Department finds that Southern's request for amortization of past non-qualified plan regulatory assets should be disallowed. The Department's position on this matter is reinforced by the questionable nature of the practice of providing pension benefits to non-employees.

The Southern SERP, BEP, and DC Plans provide benefits to two employees: the Vice President of Southern and the Senior Counsel. These non-qualifying plans pay retirement benefits over and above the internal revenue code with eligibility the same as the qualified plans. The covered employees are also eligible for the Company's matching 401(k) plan and the Southern Target Plan.

OCC argues that the costs for these plans relate only to two executives and should be disallowed based on the current economic climate. As such ratepayers should not be asked to fund costs associated with excessive benefit plans. Brief, p. 128.

The Department agrees with OCC that ratepayers should not fund benefits that are over and above the Internal Revenue Service (IRS) code, particularly in these difficult economic times. Therefore, the Department disallows all costs associated with the Southern SERP, BEP, and DC plans. The Department cites precedent for disallowing excessive benefits as stated in the CNG Decision. The Department notes that the Company did not comply with the Departmental request to report the expenses of the six non-qualifying plans separately under Late Filed Exhibit No. 82. The Company instead submitted its response to Late Filed Exhibit No. 82 with the SERP and BEP expenses combined, rather than separated.

In addition, the Department finds that Southern included in rate base a regulatory asset entitled Non-Qualified Pension Plans, amounting to $376,862. Schedule B-8.0. OCC asserts that this regulatory asset should be removed from rate base since Non-Qualified Pension Plan

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expenses should not be passed on to ratepayers. Brief, pp. 128 and 129. The Department concurs with OCC that this asset should be removed from rate base. Non-Qualified Pension Plan expenses should not be passed on to ratepayers and, therefore, Southern should not earn a return on this. Consequently, the Department removes this regulatory asset of $376,862 from rate base.

d. Employee 401(k) Savings Plan

A 401(k) plan is a qualified retirement plan under the Internal Revenue Code that allows employees to defer a portion of their gross salary into a retirement account on a pre-tax basis. Some employers agree to match a portion of each employee's contribution, although such policies are in decline. Employees are often given the option of choosing the investment vehicle for the contributions from among a menu of alternatives. Southern requested a pro forma 401(k) expense of $527,951. Schedule C-3.4.

Southern offers one 401(k) plan: the Southern Target Plan (STP) to all union and non-union employees, including executives age 21 or older with at least 12 months of service. Stone and Freedman PFT, p. 30.

The pro forma costs were calculated by deriving the test year cost for the 401(k) as a percentage of test year base payroll and applying that percentage to the expected base payroll for the pro forma period. The pay increase assumption rate used was 3%. Test year costs were approximately 2.547% of base payroll. A vacancy adjustment was made to capture the base payroll for positions expected to be filled by the pro forma year. Stone and Freedman PFT, p. 31.

The Department approves the 401(k) plan. However for the pro forma rate year, the Department decreased the Company's proposed base payroll of $20,885,394 by $185,924 as discussed in Section II.E.12. Payroll Expense - Excluding Executive. This results in a net base payroll of $20,699,470. Applying the Company's calculation rate of 2.547% to the $185,924 reduction yields a downward adjustment to the 401(k) expense of $4,735.

e. Other Benefits

i. Car Allowance

Schedule G-2.12. Executive Compensation, includes an expense for an annual car allowance for two employees: the Vice President and the Senior Corporate Counsel. This expense is $4,200 per employee for a total of $8,400 per year. During the proceeding, the Department questioned Southern regarding automobile expense related to company executives. In response to a question on auto insurance costs, the Company stated; "[t]here are no executives at Southern that have cars, automobiles, vehicles."Tr. 4/8/09, pp. 229 and 230. The Department finds that ratepayers should not have to fund excessive benefits for executive employees in these difficult economic times. The Department cites precedent for disallowing excessive benefits as stated in the CNG Decision. Based on the aforementioned, the Department disallows for ratemaking purposes the car allowance expense of $8,400, which appears to provide no direct benefit to ratepayers.

ii. Employee Recognition Programs

In its Application, Southern requested $607,092 as the incentive compensation for the rate year before applying the payroll expense percentage. This amount comprised of $318,568 for the Group Incentive Plan (GIP), $150,978 for Annual Executive Incentive Plan (AEIP) and $137,546 for other incentives that include Star Awards, Sell Awards, Credit & Collection payments, Project Incentive Plan (PIP) payments, Key Contributor (Key) payments, and Marketing Plan payments. Each of these amounts was determined based on a three-year average. Schedules C-3.3 and WPC-3.3c.

The GIP is a company-wide incentive plan and payments are made in February to employees who achieved a "good" of better rating in meeting certain financial, business and customer service parameters. PIP payments are flat dollar or percent of base pay awards made in February to employees who achieved a "good" of better rating in meeting certain performance criteria in key projects with focus on budget, timeline, key milestones and overall success of the project. The AEIP

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provides cash payments as an incentive for achieving superior performance on critical business and customer service goals. These goals are supposed to create customer and shareholder values. Participants in the AEIP are not eligible for either GIP or PIP. Key awards are for achieving objectives that are paramount to the Company's business priorities. Key awards are additional incentive payments to GIP and for certain designated individuals who not eligible for AEIP. RRP PFT, pp. 9 and 10.

Southern testified that some of the goals of the Company's incentive compensation plans, specifically the GIP and Key, focus on reducing costs and rates to ratepayers and on maintaining a high level of customer service. Examples of such goals include achieving O&M expenses less than budgeted both on a departmental and company-wide level; reducing third party damages; achieving capital spending level less than budgeted; achieving safety targets; optimizing non-firm margins (NFMs); economically growing the customer base and sales; decreasing bad debt expense; achieving waste reductions to decrease disposal fees; and optimizing inventory. Response to Interrogatory GA-357.

The Company subsequently revised its proposed incentive compensation for the rate year to $410,604. This amount consists of $273,058 for GIP and $137,546 for other incentives. The Company claimed that due to the current economic crisis, the overall financial climate and the impact to ratepayer, it excluded AEIP costs from the revised total incentive compensation expense that would be recovered in rates. Responses to Interrogatories GA-357 and GA-2 Corrected, Attachment 2, p. 24; Late Filed Exhibit No. 21.

OCC argued that the entire incentive compensation costs should be excluded from the Company's proposed total payroll expense recoverable in rates. OCC's review of the Company's incentive compensation plans revealed that payments are made for goals that are not challenging. Further, measurements of the achieved goals are set below the metrics previously achieved. For example, third party damage metrics remained the same in 2008 and 2009 at less than 3.25 per thousand tickets even though 3.11 hits per thousand tickets were achieved in 2008. The 2008 gas leak response achievement was 98%/30 minutes and 99%/45 minutes and reduced to 95%/30 minutes and 98%/45 in 2009. Brief, pp. 105-108.

OCC recommended that the bar must be raised to improve performance when established goals already been achieved. The bar has not been raised when the Company has shown that it has easily achieved a goal. Incentive plan payments are not at risk if performances are not based on improvements. OCC recommended that the entire amount of incentive compensation should be borne by shareholders until it can be established that the incentive compensation that the Company paid provides a benefit to ratepayers. If that can be demonstrated in a future rate case, then an equal sharing of a reasonable level of incentive compensation would be appropriate. Id.

AG similarly recommended that the Department disallow the recovery in rates of all costs related to the Company's incentive programs and that those expenditures should be borne by the shareholders. The objectives of these plans mainly benefit the shareholders and not ratepayers. The plans focus on earnings and profitability rather than performance to customers. Brief, pp. 4 and 5.

The Department believes that under present conditions, employees in virtually every industry have seen a suspension of elective incentive payments from their employers. Many firms are laying off employees, cutting pay, suspending raises, instituting furlough days and implementing a variety of other payroll cost cutting measures. The regulated utility industry should not be immune to the realities of the present economy.

It appears to the Department that a substantial portion of the dollar value of payments made under the AEIP, GIP, PIP, and Key incentive programs are made to managers and higher-level supervisors. The Company also stated that the only participants in the Key plan are "three or four" highly placed managers and directors. Tr. 4/8/09, pp. 225 and 226. Further, the Department believes that Company managers and executives should perform to the best of their ability as a condition of their employ-

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ment. Additional compensation for managing effectively should not be required. The Company agreed that the executive staff would continue to do their jobs "properly and efficiently" in the absence of these incentive payments. Tr. 4/8/09, p. 218.

The Company stated that the employee rating scale for the GIP and PIP plans are a three point scale: low, good, and high, and that a rating of "good," the midpoint or average, is sufficient for eligibility to earn an award under both the GIP and PIP programs. Tr. 4/8/09, pp. 223-225. Incentive payments that are directed almost exclusively to upper management and based on attaining acceptable or expected performance does not provide any benefit to ratepayers.

The format of WPC 3.3c does not show specific account amounts for the PIP and Key programs. Rather, the two programs along with several others are valued at $137,546. It appears to the Department that lower level supervisors are eligible for the PIP, while only higher level executives are eligible for the Key plan. The Department will allow the funding of the PIP, but disallows the AEIP and GIP and Key plan. The Department directs the Company to furnish an accounting of the shared cost of the PIP and Key plan (a total of $137,568, including several other programs) indicating the dollar amount designated for each of the plans or programs. Therefore, the Department will adjust the Company's revised incentive compensation expense of $410,604 and allows $137,546 of this expense. The Department disallows $202,991 of the proposed incentive compensation expense. The disallowed amount is determined by multiplying $273,058, which the difference between the proposed amount of $410,604 and the allowed amount of $137,546, by the adjusted payroll expense factor of 74.34%.

iii. Executive Insurance

Director and officer insurance is purchased by a company to insure against claims generated by losses resulting from the illegal or improper actions of its executives. As such, this insurance primarily protects the company's shareholders. Southern lists a pro forma insurance expense of $99,133 which includes: crime, fiduciary and professional liability coverage. Schedule C-3.34. The professional liability insurance covers actions by the Company's attorneys and the fiduciary insurance covers actions by executive fiduciary officers. Tr. 4/8/09, pp. 226 and 227. Crime insurance covers unlawful acts by employees, such as embezzlement. Tr. 4/8/09, pp. 228 and 229. The Department finds that these expenses totaling $99,133 inordinately benefit shareholders rather than ratepayers, and will disallow this expense. Were the Company to experience these types of losses, the Department would likely find the Company imprudent in its hiring, management or control. Premiums insuring against these losses are unnecessary.

14. Rate Case Expenses

The Company originally requested recovery of $2,240,000 in rate case costs as an annual amortization expense of $560,000 over the next four years. Schedule C-3.12; RRP PFT, p. 29. Southern subsequently reduced its request by $240,000 to $2 million. This reduction included $200,000 for the estimated costs for the Department consultants that were not used, and a $40,000 reduction of the working capital lead/lag study costs. Response to Interrogatory GA-2 Corrected, Attachment 2, p. 31.

The Company partially justifies its $2 million rate case cost for rate case outside services by stating that its legal costs are appropriate and reasonable given the scope of work completed by counsel. The Company argued that it would not be prudent or cost effective to hire permanent in-house attorneys capable of performing all of the legal work required for a rate case. The Company claimed it retains the legal services of Dewey & LeBoeuf, LLP (Dewey) because Energy East retained Dewey to perform legal services for its operating companies. Dewey is familiar with the Company's prior rate cases and operations, and possesses specialized rate case expertise, which allows it to quickly step into rate case litigation. The Company stated that Iberdrola has a long-term relationship with Latham & Watkins, LLP (Watkins) and that Watkins has "significant experience

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in energy matters" including legal expertise on the current capital market and its affect on the Company's return on equity (ROE) requirement. The Company stated that this rate case is complicated by matters such as the ERP and decoupling. Using the discreet services of outside legal and consulting services is cost-effective as compared to increasing internal staff to perform work that is essentially infrequent. Brief, pp. 91-94.

OCC stated that the Company's rate case expense level is unprecedented, unsupported in the record and demonstrates a pattern of inefficiencies and overspending in clear disregard for the financial realities faced by the Company's ratepayers. In The United Illuminating Company (UI) rate case Decision dated March 4, 2009 in Docket No. 08-07-04,Application of The United Illuminating Company to Increase Its Rates and Charges, (UI Decision) the request for the rate case expense was $933,000. The UI rate case contained similar issues related to the economic downturn and decoupling. Brief, pp. 136-144. OCC recommended the following adjustments to the Company's rate case expenses.

1. Remove $650,000 from the $850,000 of estimated outside legal costs because the Company hired two national law firms to work on the rate proceeding. Their work and presence at the hearings, along with Southern's in-house counsel, appears duplicative and wasteful. The estimated costs are for a period when both Southern and its sister utility, CNG, are presenting rate cases before the Department with overlapping testimony that has been administratively noticed in these dockets.
2. Remove the estimated $40,000 cost for a conservation consultant that provided no value-added services from information already provided by the ECMB or at minimum reducing the cost by 50% or $20,000.
3. Remove $100,000 from the $400,000 cost for Towers Perrin, Southern's pension and OPEB consultant, since only $222,984 of actual billings have occurred through April 18, 2009, and the Company's estimate appears too high.
4. Disallow the $75,000 cost of performing a full Depreciation Study when the last Depreciation Study was done only two years ago. The current Depreciation Study was not timely or necessary and thus should not be funded by ratepayers.
5. Remove $50,000 of the $100,000 estimated cost of the Company's ROE expert who did not develop, but merely attested to Energy East's proposal for a capital structure and ROE.

Id.

Accordingly, OCC recommended that the Department only allow total rate case expenses of $1,085,000 to be amortized over a four-year period. This results in an annual amortization of $271,250 versus the $500,000 requested by the Company.Id.

AG recommended that the Department reject all of Southern's rate case expenses request or approve not more than $800,000, the amount approved in the UI Decision. Brief, pp. 9 and 10.

The Department notes that although a comparison of UI's rate case cost for total outside services of $783,000 and the Company's request for $2,000,000 does not provide a sufficient basis for adjustment, the use of experience in-house personnel intimately knowledgeable of the Company practices and available for day-to-day and recurring regulatory activities is compelling. The Department cannot condone the use of duplicative and potentially excessive outside legal services from two national law firms, which represented the Company along with internal counsel during the proceeding. In this regard, the Department will cap outside services legal expense at $600,000, thereby disallowing $250,000 in outside legal service costs from the total rate case expense.

The Department agrees with OCC regarding employment of a conservation consultant when the ECMB's work and findings were readily available and disallows $20,000 of this expense. The Department also disallows $100,000 of estimated pension and OPEB consultant costs. The $400,000 estimate appears high compared to the consultant's actual billings through April 18, 2009, and that certain pension funds are not considered to be ratepayers' responsibility. Regarding the Company's ROE expert, the Department agrees with OCC that the Company's ROE expert witness merely confirmed the capital structure and reduces this cost by $50,000. In addition, the expert witness testimonies are practically and

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essentially the same for both Southern and CNG. Regarding the Depreciation Study, this expense will be allowed because the Department requested it. However, the Department and OCC found significant issues regarding assets being misclassified in certain accounts. This resulted in incorrect depreciation rates for the affected accounts. See, Section II.C, Rate Base. When the Company files the rate base audit results, it shall also include adjustments to the depreciation rates that resulted from the audit. The intention of the Department is that any cost related to correcting the depreciation rates and study will be borne by the shareholders.

The Department is somewhat puzzled by the Company's claim that having two sister companies litigate two separate rate proceedings almost simultaneously produces few efficiencies and synergistic savings in legal and other outside consultant costs. In its Reply Brief, the Company argues that its proposed rate case expenses were necessary in a proceeding that was initiated based upon a Department order. Reply Brief, pp. 75-79. The Department does not question the Company's need or requirement for these expert witnesses or legal advisors. However, the high costs for these witnesses and legal advisors needs to be evaluated for prudency. The Department makes the aforementioned adjustments in its belief that $1,580,000 for outside services for a single rate case, regardless of its complexity, should be a sufficient amount to provide the Company with adequate expertise to present its case. In the current period of economic turmoil, the Company must be vigilant in providing ratepayer related services at a reasonable cost. The Department also noted that despite its use of extensive outside expertise, the Department alerted Southern to a substantial number of errors and inconsistencies in its original filing that the Company was compelled to correct.

In summary, the Department allows a total outside service rate case expense of $1,580,000 ($2,000,000 - $250,000 - $20,000 - $100,000 - $50,000), and an annual amortization amount of $395,000 over four years ($1,580,000 / 4). This results in an adjustment to rate case amortization expense of $105,000 ($500,000 - $395,000). The proposed rate base will be reduced by $420,000.

15. EEMC/USSC Allocation

Affiliate charges included costs directly charged or allocated to Southern by the Energy East Management Corporation (EEMC) and the Utility Shared Services Corporation (USSC). In 2000, EEMC was formed to assist all Energy East subsidiaries in such functions as corporate planning, human resources, tax services, internal audit, legal services and commodity planning. In 2003, Energy East created a Utility Shared Services Organization whose cost are split between five operating utilities to provide information technology, purchasing, accounting and payroll assistance. Revenue Requirements Panel PFT, pp. 31 and 32. For the test year, Southern was allocated charges of $5,817,432 and $2,443,924 by USSC and EEMC, respectively. It is unclear to the Department how EEMC and USSC total expenses have been allocated to Southern such that Southern bears $8.95 million charge. Southern initially requested a $691,556 increase from the test year amount of $8,261,356 to a rate year total of $8,952,912 for all charges associated with EEMC and USSC. The rate year's proposed allocated charges are $6,346,959 and $2,605,953 from USSC and EEMC, respectively. Schedule C-3.16. In its updated filing, the Company reduced charges from EEMC by removing $330,000 in incentive compensation. The adjustment reduced the total allocated to Southern from these shared services companies for the rate year to $8,622,912. Late Filed Exhibit No. 21; Response to Interrogatory GA-2, Corrected, p 32.

The Company requested $228,928 associated with the allocation of payroll expenses for filling vacant and proposed new positions at EEMC and USSC from the test year to the rate year. The request is for adding four new positions at EEMC and one new position at USSC and the filling of 32 vacancies. Late Filed Exhibit Nos. 46 and 47.The total interest charges in the test year allocated to Southern and other affiliates was $1,752,794. These Interest charges are related to working capital loan at the USSC level. Southern's portion of these charges was $128,784. ADR-20 Attachment 1, p. 69;

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Tr. 04/13/09, p. 516. Interest is calculated using an Energy East's weighted average cost of capital rate applied against the outstanding daily loan balance. The average loan balance during the test year was approximately $15 million. Late Filed Exhibit No. 36. For the rate year, the Company is proposing $137,640 as the intercompany interest expense from USSC to Southern. Interrogatory Response to OCC-275, p. 2.

OCC is concerned and contended that Southern failed to provide detailed supports to substantiate allocated charges from EEMC and USSC. OCC is especially troubled that affiliate charges are being allocated into cost categories for which derivations of these costs were based on vague budgeted amounts from EEMC and USSC. Brief, pp. 131-136. OCC recommended the removal of non-qualified pension costs allocated from EEMC of $182,179; the removal of costs allocated to Southern associated with filling of vacant and new positions at EEMC and USSC of $222,928; a $137,640 reduction to remove the interest expense charged to Southern from USSC related to loans from EEMC and a reduction of $139,155 to remove non-executive incentive compensation. Id.

Finally, OCC recommended that an audit be performed for a detailed review of the charges from EEMC and USSC. OCC contends that the Company failed to provide detailed explanations regarding EEMC and USSC budget assumptions and how the dollar amounts in the cost categories were derived. Southern utilized these budgets to project the pro forma amounts in the instant proceeding. OCC claimed that given the large amount of costs allocated to Southern, the Department should consider requiring an affiliate transaction audit, that is not time constrained by the statutory requirement of a general rate case, for a detailed review and analysis of costs allocated to Southern by USSC and EEMC. Id.

The Department finds that the Company made the appropriate deduction regarding incentive compensation. Therefore, the Department will not be reducing the affiliate charges by $139,155 of incentive compensation costs as recommended by OCC. In Section II.E.13.c. Non-Qualified Pension Plans, the Department removed non-qualified pension expenses for the Company. The Department finds that the same deduction to be appropriate for its affiliates, and will reduce affiliate charges by $182,179. The Department agrees with OCC's recommendation to remove the $228,928 associated with filling of vacant and new positions at EEMC and USSC. The Department also finds the loan interest charge of $137,640 between EEMC and USSC to be overstated. It is the Department's position that regulated utilities should not be paying charges to affiliates that are significantly in excess of costs to obtain similar services from unrelated third parties. The Company's cost of short term debt is a better proxy for its working capital borrowings than an affiliate debt rate which approaches 11%. The Department rejects the interest rate of 10.7% used by EEMC and instead uses Southern's cost of short-term debt percentage of 2.48% as calculated in Section II.R.3. Cost of Short-Term Debt or 23.2% of the EEMC rate (2.48% / 10.7%). The Department will allow an interest charge of $31,932 (23.2% of $137,640) and reduces the intercompany interest charges by $105,708 ($137,640-$31,932).

The test year's charges allocated to Southern included $409,214 and $1,437 for stock option expense by EEMC and USSC, respectively. See, ADR-20 Attachment 1, pp. 69 and 70. It was established in this proceeding that Energy East no longer has publicly traded stock shares following its merger with Iberdrola. Response to Interrogatory GA-227. Also, no evidence was provided in this proceeding to support the position that Iberdrola, whose stock shares are only publicly traded in Europe, has any plan to establish stock option compensation plan for Energy East's subsidiaries. The Department believes that the stock option expense allocated to Southern is a non-recurring expenditure and should not be included in allocated charges proposed for the rate year. Therefore, the Department disallows the total stock options expenses of $410,651 allocated to Southern by EEMC and USSC in the test year from the rate year's expenses.

In total, the Department disallows $927,466 ($182,179 + $105,708 + $$228,928 + $410,651) from the Company's total EEMC and USSC charges request. The total allowed allocated costs for these shared services com-

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panies is $7,695,446 ($8,622,912 less $927,466). The Department finds that the affiliate services provided by EEMC and USSC to Southern demand a Department investigation pursuant to Conn. Gen. Stat. §16-8c.

In its Written Exceptions, the Company stated that the adjustment for stock option expenses allocated to Southern by EEMC and USSC made in the draft Decision is duplicative and the Company referenced Late Filed Exhibit No. 21. Written Exceptions, p. 88.

The Department reviewed this exhibit and determined that the Company made adjustments for incentive compensation of $330,000 allocated to Southern by EEMC. In addition, the Company made an adjustment for its own stock option expense. However, the Company did not make an adjustment for stock option expenses that were allocated by EEMC and USSC. See, Schedule C-3.16; Late Filed Exhibit No. 21; ADR-20 Attachment 1, pp. 69 and 70; Response to Interrogatory GA-2 Corrected, Attachment 2, p. 32.

16. Environmental Remediation Costs

The Company proposed a revised total deferred environmental expense of $10,344,093 to the midpoint of the rate year December 31, 2009. These costs relate to environmental contaminations for a number of sites, including but not limited to, the Chapel Street manufacturing gas plant (MGP) site in New Haven, the current operations center at Marsh Hill Road in Orange, the former MGP at Pine Street in Bridgeport and the Trumbull liquid propane (LP) facility. Southern received $3,842,854 in a net insurance recovery and $487,500 in a law suit recovery. Tr. 04/09/09, p. 279; Response to Interrogatory OCC-58, Attachment 1, Revised Schedule WPC-3.20. Southern's cumulative amortization as of June 30, 2008 is $2,559,419, which is calculated in the table below:

Amortization of Environmental Remediation Costs

Docket No.	Effective Dates	Annual Allowed Amount	Cumulative Amount
05-03-17PH01	1/1/06 - 06/30/08	$500,000	$1,250,000
99-04-18	2/1/00 - 12/31/05	$ 98,365	$ 581,993
Prior to 99-04-18	Prior to 2/1/00		$ 727,426
Cumulative Amortization as of 6/30/08			$2,559,419

Response to Interrogatory OCC-58, Attachment 1; Revised Schedule WPC-3.20.
In addition, Southern included an amount of $500,000, which represents the amortization from 7/1/08 through 6/30/09. The Company is proposing to maintain the annual amortization at the same level of $500,000, which was allowed in the 2005 Rate Case. Southern proposed to recover from ratepayers $2,954,320 ($10,344,093 - $2,559,419 - $3,842,854 - $487,500 - $500,000). Southern proposed an amortization period of six years by dividing the remaining deferred environmental expenses of $2,954,320 by the currently approved amortization rate of $500,000. RRP PFT, p. 37.

a. Chapel Street, New Haven Site

On July 17, 2008, the Connecticut Department of Environmental Protection (DEP) directed the Company to investigate the source of an oily sheen on the Mill River, which is adjacent to the Chapel Street site in New Haven. Tr. 04/9/09, p. 277. The Company investigated the source of the oily sheen and has taken steps to elim-

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inate and contain the sheen until the source is found. Southern will implement a temporary remediation measure until a permanent solution is determined. RRP PFT, p. 35. Southern indicated that it already incurred $163,048 in expenses between July 1, 2008 and October 31, 2008. Response to Interrogatory OCC-58, Attachment 1; Revised Schedule WPC-3.20. This amount consists of expenses related to digging a number of test pits to determine the cause of the oily sheen, determination of the condition of the existing storm drain and the disposal of 2,400 tons of impacted soil from the site. Tr. 04/9/09, pp. 281 and 282.

The Company's investigation revealed that a hundred year old storm drain broke and rotted away within 15-20 feet of the seawall. Storm water that was normally conveyed through this pipe proceeded to erode materials contaminated with coal tar and other contaminations into the Mill River. There is a tenant near the Company's Gateway Terminal that routinely runs heavy equipment on the Mill River site. However, there is no evidence indicating the tenant's activities caused the damage; but rather the age of the infrastructure was the cause. For this reason, the Company did not seek any recuperation of the damages from the tenant. Tr. 4/09/09, pp. 279 and 280.

At this time, the damage storm water drain system at the Chapel Street site has been repaired. A collection facility was installed at the seawall to collect non-aqueous liquids or oils that float on top of the water. Tr. 04/09/09, pp. 277-279. Southern estimates that it will incur an expense of $892,012 between November 1, 2008 to December 31, 2009, based on estimated future bills for the repair of the Mill River Storm water system and site remediation. Tr. 04/09/09, pp. 284 and 285; Response to Interrogatory OCC-58, Attachment 1; Revised Schedule WPC-3.20.

b. Marsh Hill Road, Orange Operation Center

At the Orange Operation Center, located on Marsh Hill Road, hydraulic fluid leaked into the soil in the facility's maintenance garage due to the failure of the hydraulic lifts. In December 2004, Southern reported the leak to DEP and took immediate steps to clean the contaminated soil. The Company also conducted an investigation to determine the parameters of the soil contamination and remediation for this leak. Since the last rate case, Southern incurred expenses totaling $36,295 for remediating this site. RRP PFT, p. 35; Response to Interrogatory GA-3, Attachment Read-In C. Between July 1, 2008 and October 31, 2008, the Company incurred an additional remediation expense of $280. Revised Schedule WPC 3.17. Southern expects to incur an additional expense of $200,528 between November 1, 2008 and December 31, 2009 for the Orange garage and other remediation, for a total expense of $237,103 ($36,295 + $280 + $200,528). Revised Schedule WPC-3.20.

c. Pine Street, Bridgeport Site and Trumbull LP Facility

Southern incurred costs of $2,366,746 related to the Pine Street site in Bridgeport and $51,736 for the LP facility in Trumbull. The Pine Street remediation process is broken into two parts. Part A is complete and addressed the contamination of the groundwater on the site. Part B is the remediation of the contaminated soil and is not complete. RRP PFT, p. 33. Regarding the Trumbull LP facility, the site's remediation is not complete and currently the site is being decommissioned. Southern remediated friable asbestos from this site and expects to incur additional cost to complete the remediation process. RRP PFT, p. 33.

Southern testified that it will incur additional costs to complete the remediation process for both sites. The estimated expense for remediating these sites is included in the Company's proposed total net amount of $2,559,419, what would be amortized over a six-year period. Revised Schedule WPC-3.20. Southern received $487,500 from a law suit recovery against the environmental engineering firm that designed the Groundwater Treatment System for the Pine Street site. Tr. 04/09/09, p. 285; Response to Interrogatory OCC-61.

d. Summary

In the Decision dated December 21, 1985, at page 55 in

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Docket No. 88-05-25,Application of The Connecticut Light and Power Company for Approval of New and Amended Rate Schedules, the Department allowed pro forma expenses for coal tar remediation and suggested that ratepayers would be responsible for the cost. In the Decision dated December 15, 1993, beginning at page 11, in Docket No. 93-02-04,Application of Connecticut Natural Gas Corporation to Amend Its Rate Schedules, the Department allowed the creation of a deferred liability account for the remediation of coal tar expenses. The Department did not allow deferred expenses for environmental remediation expenses at another site because they were not coal tar remediation expenses. Environmental remediation meant coal tar remediation only and shareholders would be responsible for other environmental remediation expenses outside the test year or between rate cases. CNG was admonished for including non-coal tar remediation expenses in its pro forma adjustments.

In the Decision dated December 16, 1992, at page 21, in Docket No. 92-06-05,Application of The United Illuminating Company for a Rate Increase, the Department allowed deferred environmental remediation for asbestos removal costs because the clean-up costs would make the property more marketable and sale proceeds would accrue to ratepayers.

In CL&P et al. v. PUC et al., No. 143947 (Memorandum of Decision)(1978) (Unpublished Decision) actual test year expense items were not allowed recovery. The court held that, "... the companies must not only establish the legitimate occurrence of a given expense in the test year, but also the likelihood that the expense is representative of future operations."The companies had "failed to carry their burden of proof concerning the fully reoccurring nature of the

The Department approves recovery of the Company's proposed remediation expenditures related to the Pine Street site in Bridgeport because it is test year coal tar remediation. However, The Department disallows the Chapel Street site expense of $1,055,060 ($892,012 + $163,048) related to the repair of the Mill River's storm water system and site remediation because this environmental remediation expense is not for coal tar and is a non-reoccurring expense. Additionally, the Department disallows the expense of $237,103 for the remediation costs of the Marsh Hill Road property because this environmental remediation expense is not for coal tar remediation, but the result of a leaking hydraulic garage lift fluid, which is a non-reoccurring expense. Further, the Department disallows the expense of $51,736 for asbestos remediation at the Trumbull LP facility because it is not coal tar related. For the Chapel Street, Marsh Hill Road property, and the Trumbull LP facility, no deferral expenses for the test year or rate year will be included in revenue requirements.

The Company must not only establish the legitimate occurrence of a given expense in the test year, but also the likelihood that the expense is representative of future operation for it to be reoccurring and a proper rate year expense. The Company failed to carry their burden of proof concerning the fully reoccurring nature of the items. Refer to CL&P et al. v. PUC et al., No. 143947 (Memorandum of Decision)(1978) (Unpublished Decision), pp. 24-26.

In total, the Department denies $1,292,163 ($1,055,060 + $237,103) of Southern's proposed remediation expense to be recovered from ratepayers. Therefore, the net amount to be recovered from ratepayers is $1,662,157 ($2,954,320 - $1,292,163). The Department maintains the Company's proposed six-year amortization period. Therefore, Southern will be allowed to recover an annual expense of $277,026 ($1,662,157 / 6). The Department disallows amortization expense of $222,974 ($500,000 - $277,026). Further, the Company's rate base shall also be reduced by $1,292,162 to reflect this disallowance.

17. Daily Demand Metering

A DDM device sits atop of the meter and transmits gas consumption readings. By Decision dated May 1, 2002 in Docket No. 99-04-18PH04,DPUC Review of The Southern Connecticut Gas Company Rate and Charges Phase IV - Rate Design (2002 Decision), the Department approved a minimum annual consumption threshold for telemetering or DDM for 5,000 ccf for

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firm sales and transportation service C&I customers. The 2002 Decision also required Southern to install DDMs on all firm customers meeting the minimum threshold requirements. In the above cited Decision, Southern was ordered to submit a plan to address the installation of DDM equipment for all customers without DDMs that met the new criteria by June 1, 2002. 2002 Decision, p. 7. On November 13, 2008, Southern submitted a status report for the installation of the telemeters. The report indicated that the initial deployment of the DDM devices for C&I, interruptible and DG customers was completed. Southern acknowledged that it has been approximately eight years since it was ordered to install DDMs on customers using in excess of 5,000 ccf or more annually. Response to Interrogatory GA-3, Read-In H.

Currently 3,564 C&I customers consume greater than 5,000 ccf annually, which requires that DDMs be installed. Tr. 04/13/09, pp. 436 and 858. As of February 2009, Southern installed 3,203 DDM devices on individual customer's meters, which are currently reporting hourly reads. The difference of 361 between the two above numbers (3,564 - 3,203) is that these DDM devices were no longer needed and have not been removed from the customer's meter. Customers transferring between rate classes are the primary reason why these units are installed on customer's meters. Tr. 04/13/09, pp. 436 and 437. Southern reported approximately seven of its General Service Rate (Rate GS) and Rate LGS customers did not have telemetering devices installed as of the date of the hearing. The seven customers without DDMs are the result of customers transferring between rate classes. Response to Interrogatory GA-48.

On April 13, 2006, Southern contracted with CellNet to install a new DDM wireless system to provide hourly readings for all firm and sales transportation customers with annual consumption greater than 5,000 ccf. Response to Interrogatory GA-48. The hourly reading transmits the consumption amount to the neighborhood receivers. The receiver then sends those readings back to CellNet's operations center, which sends the data to Southern. The Company posts the consumption data on the website for customers and marketers to view. Tr. 04/13/09, p. 440. Hourly reads will be provided to the Company using the CellNet wireless radio-base DDM system. Southern explained that it requires neighborhood receivers to ensure that the wireless radio-base system could report reads. The receivers are then installed at strategic locations to pick up frequencies. For those customers with DDMs installed previously, Southern used the phone-based Metscan units to monitor customers' daily consumption. The record is unclear about the number of customers that used the Metscan unit prior to the installation of the wireless radio-base system on meters of all customers that needed DDMs. Tr. 04/13/09, pp. 439 and 440.

In this rate case, Southern proposed to install 933 new DDM devices on meters of Rate RMDS customers to comply with the Department's recent Decision dated October 15, 2008 in Docket No. 05-03-17PH02,Application of The Southern Connecticut Gas Company for a Rate Increase - Rate Design (Rate Design Decision). That Decision required Southern to implement a demand charge for Rate RMDS customers. Southern testified that 607 Rate RMDS customers consume more than 5,000 ccf annually. Response to Interrogatory GA-309. According to Southern, it included the 933 DDM devices discussed above in the total rate year DDM count of 4,698 devices for a proposed expense of $373,498. Reis, Dobos, Nunn and McNally PFT, pp. 11 and 12; Schedule C-3.32

The Company proposed a monthly DDM cost of $6.63, which includes $6.25 per unit, plus 6% sales tax of $.375. The monthly cost of $6.63 per DDM includes installation cost and O&M expense. This results in an expense of $373,498 for the 4,698 DDM devices in the rate year. Schedule C-3.32. Southern has a ten-year contract with Itron where the monthly cost per unit remains the same for the first five years. In the sixth year, Southern will adjust the cost per DDM based on the consumer price index and at the end of the ten-year contract, Southern would have the right to renegotiate the contract. Tr. 04/13/09, p. 444.

The record indicated that 607 Rate RMDS customers are eligible for a DDM. As discussed in Section

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II.K.5.c. Residential Multi-Dwelling, the Department grossed up the test year number of customers on Rate RMDS to 669 to account for future customer growth. Therefore, the allowed number of DDMs for the rate year is 4,233 (3,564 + 669). To calculate the corresponding DDM expense the Department multiplied the total number of DDMs, times total unit rate times 12 months, which equals a total allowed DDM expense of $336,778. The resulting reduction in the DDM expense is equal to $36,720 ($373,498 - $336,778).

Hess addressed issues concerning the administration, deployment and operation of the Company's DDM system. Hess's concerns were related to Southern's monthly missing reads report, deployment of the DDM devices and the Company's monthly performance standard. Tr. 04/14/09, pp. 806-813. Southern testified that as of April 5, 2009, 3,575 DDMs were installed and 3,375 devices were calling in 24 reads a day. Tr. 4/14/09, p. 810. When DDM data is not available, the Company uses a formula based on historical monthly data prorated by the number of degree days each day. Tr. 4/14/09, p. 814.

Southern defines an operating DDM as one that provides more then one DDM read during a 24-hour time period. Tr. 4/14/09, pp. 805 and 806. The contract between Cellnet and Southern sets the performance standard for meter readings. The standard requires that the meter reads every day be accurate up to a 96.5% level for the first 12 months and 98.8% level thereafter. Southern Written Exceptions, p. 94. But if the vendor does not provide 24 hourly reads per day, Southern is not responsible for paying the vendor the individual meter charge. Tr. 04/14/09, p. 812.

The Department finds that customers that do not receive the expected service from a DDM should not pay a DDM charge. The Company shall not charge any customer without a DDM a DDM charge. The Company shall not levy a DDM charge on any customer whose meter readings do not meet the contract standards. Southern will be directed to file an annual report in a spreadsheet indicating the dollar amount of DDM charges billed to customers and the dollar amount of DDM charges also billed to the Company by the Vendor. The Company shall keep records and file as part of its next general rate proceeding an itemized accounting of the revenues received from ratepayers for DDM services and the costs borne by the Company for services provided by DDM related vendors. This will allow the Department to ensure that the amount included in revenue requirements for DDMs matches the costs borne by the Company to provide the expected DDM service.

The Company shall continue to file the monthly Missing Reads Report as directed in the Decision dated September 5, 2007 in Docket No. 06-04-04,DPUC Review of Cost Allocation Issues Related to Natural Gas Transportation Services (Cost Allocation Decision), enhanced as necessary, and described below. The report shall be in an active spreadsheet that can be summarized to evaluate the DDM system's performance and any DDM charges billed or waived by customer class. The Department intends to use the report to monitor and form the basis for any changes or remedial action necessary to ensure prudent and efficient management of this historically troubled area.

18. Conclusion on Expenses

In addition to the above noted specific adjustments to expenses, the revenue requirements model used by the Department further adjusts expenses, including taxes for the impacts of specific adjustments on uncollectible expense, gross earnings tax, income taxes and interest expense synchronization. The impact of all the adjustments made by the Department is shown in Tables II and III in the Appendix.

F. INCOME TAXES

1. Gross Earnings Tax

Southern calculated its gross earnings tax (GET) using 4% for residential and 5% for C&I customers. The Company stated that it applies the full 5% credit to the bills of industrial customers who qualify for the manufacturing rebate (MR). Southern originally proposed a blended GET rate of 4.35% based on the total pro forma

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revenue at present rates. The Company stated that it follows the federal tax return schedule format in estimating its operating and non-operating GET obligations. Pro forma revenue at present rates is calculated by multiplying billing determinants by applicable rates that include the GET. It is then reduced by the manufacturing GET rebate applicable to those C&I customers who qualify for the 5% credit. The difference between the total revenue at present rates and the total revenue used to calculate the proposed GET rate and pro forma GET expense is due to the NFM mechanisms. Schedule A-2; RRP PFT, p. 47; Response to Interrogatory OCC-72 Attachment; Tr. 4/08/09, pp. 141-144. In its updated filing, the Company revised and reduced the GET blended rate to 4.34%. Response to Interrogatory GA-2 Corrected, Attachment 2, p. 2. The Department believes that the Company double counted the manufacturing rebate (MR) and erroneously added back NFM mechanism revenue and Firm Transportation Service (FTS) surcharge to the base revenue at present rates for calculating GET expense as detailed below.

Department's Analysis of Southern's Calculation of GET Expense on Pro Forma Revenue

Line	Item	NFM	Non-NFM	Total
1	Total Revenue at Present Rates	$30,410,163	$358,992,083	$384,402,246
2	Add-back MR	$674,897	$244,993	$919,890
3	Add-back MR	$674,897	$244,993	$919,890
4	Total Revenue at Present Rates with MR (Line 1+Line 2+Line 3)	$31,759,957	$354,482,069	$386,242,026
5	Add FTS Surcharge	$0	$3,780,316	$3,780,316
6	Add NFM Mechanism	$16,942,217	0	$16,942,217
7	Add NFM-Coral Alliance	-$4,966,624	0	-$4,966,624
8	Revenue Basis for GET (Line 4+Line 5+Line 6+Line 7)	$43,735,550	$358,262,385	$401,997,935
9	GRT Removal	95%	95%	
10	Revenue without GET (Line 8xLine 9)	$41,548,773	$340,349,266	$381,898,038
11	Proposed GET Expense on Pro forma Revenue (Line 8-Line 10)	$2,186,778	$17,913,119	$20,099,897

Response to Interrogatory GA-2 Corrected Attachment 2, pp. 18-20 and 39.

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The Company double counted the GET expense on MR, NFM and FTS surcharge. These PGA firm service gas cost off-sets were already netted out of operating revenue at present rates. The Company calculated GET expense in excess of the amount for which it will be obligated. The Company's approach does not make the Application's revenue request PGA neutral. The Company's calculation overstates the revenue basis for calculating GET expense by $16,675,799 ($16,942,217 - $4,966,624 + $919,890 + $3,780,316). This amount is also the difference between the Company's erroneous base revenue at present rates of $401,997,935 and the correct base revenue of $385,322,136. Based on the Company's approach, the net NFM to be refunded in the PGA would be $23,993,559, which is $41,548,773 (Line 10) less the interruptible gas costs of $17,555,214. See, Interrogatory Response to GA-2 Corrected Attachment 2, p. 20. The Department's calculations of GET expenses for NFM mechanism and FTE surcharge revenues are detailed below.

Calculation of GET Expense on NFM and FTS Surcharge Revenues

Line	Item	NFM	Non-NFM	Total
1	Total Revenue at Present Rates	$30,410,163	$353,992,083	$384,402,246
2	Add-back MR	$674,897	$244,993	$919,890
3	Revenue Basis for GET (Line 1+Line 2)	$31,085,060	$354,237,076	$385,322,136
4	GRT Removal	95%	95%	
5	Revenue without GET (Line 3xLine 4)	$29,530,807	$336,525,222	$366,056,029
6	GET on Pro forma Revenue (Line 3-Line 5)	$1,554,253	17,711,854	19,266,107
7	Reconciliation:			
8	Interruptible Gas Costs	$17,555,214		$17,555,214
9	Add: On System NFM	$16,942,217		$16,942,217
10	Add: NFM-Coral Alliance	-$4,966,624		-$4,966,624
11	NFM Revenue without GET (Lines 8+9+10)	$29,530,807		$29,530,807
12				
13	Difference: Column A only (Line 11-Line 5)	$0		

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14			
15	FTS Surcharge to be returned	$3,780,316	$3,780,316
16	Add GET	0.95	0.95
17	FTS Surcharge with GET (Line 15/Line 16)	$3,979,280	$3,979,280
18	FTS Surcharge billed to Customers Per Southern	$3,979,280	$3,979,280
19	Difference (Line 17-Line 18)	$0	$0

Interrogatory Response to GA-2 Corrected Attachment 2, pp. 19, 20 and 39.

The Department reconciles the total NFM revenue without GET expense to zero (Line 11-Line 5). Similarly, the Department reconciles the FTS surcharge the Company stated would bill to customers to the FTS surcharge with GET (Line 11-Line 5). The Company's attempt to add back the NFM and FTS surcharge would double count the amounts associated with these items and grossly overstates the pro forma revenue at present rates for calculating GET expense. The Department's calculations of the GET rate and expense based on the total pro forma revenue at present rates are below:

GET Rate and Expense

Line	ITEM	PRO FORMA
1	Pro Forma Revenue at Present Rates	$435,040,345
2	Add PGA Roll-in at Present Rates	($ 50,638,099)
3	Pro Forma Revenue with PGA (Line 1 + Line 2)	$384,402,246
4	Residential General	$ 15,547,058
5	Residential Heat	$221,788,105
6	Multifamily Sales Residential	$ 10,207,525
7	Multifamily Firm Transportation - Residential	$ 1,924,257
8	Total Residential Revenue at Present Rates (Sum of Lines 4,5,6,7)	$249,466,945
9	Non-Residential Revenue at Present Rates (Line 3 - Line 8)	$134,935,301
10	Add Back: Manufacturing Rebate	$ 919,890
11	Total Revenue at Present Rates for GET (Sum of Lines 8, 9,10)	$385,322,136

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12	Total GET @ 5% (Line 11 x 5%)	$ 19,266,107
13	Less Residential Credit (1%) (Line 8 x 1%)	($ 2,494,669)
14	Less Manufacturing Rebate	($ 919,890)
15	GET Expenses	$ 15,851,547
16	Allowed GET Rate (Line 15 / Line 11)	4.1138%
17	Proposed GET Expense at present Rates	$ 16,658,337
18	GET Expenses Adjustment (Line 17 - Line 15)	$ 833,790

Id, pp. 3 and 65; Response to Interrogatory GA-2, Supplement #2 Att. 1, p. 3.

The Company added pro forma other revenue of $3,036,646 but did not add "Other Revenue Adjustments" of negative $15,292,921 to the total pro forma operating revenue at present rates used to calculate both the GET rate and expense. Schedules C-31.1 and WPC-3.1; Response to Interrogatory OCC-72. In its updated filing, the Company reduced "Other Revenue Adjustments" to negative $15,905,909. Response to Interrogatory GA-2 Corrected, Attachment 2, p. 18. This amount represents the net estimated revenue from non-firm and ancillary activities to be returned to firm customers in the PGA.

For the purpose of calculating the GET rate and expense for the pro forma period at present rates, the Company incorrectly included the net revenue from interruptible and off-system activities in the total pro forma revenue at present rates. The Department found that the Company calculated non-residential revenue at present rates of $153,605,707 ($135,207,907 + $18,397,000). See, Schedule C-3.52; Response to Interrogatory OCC-72. This amount is significantly higher than the $134,935,301, which is the total pro forma revenue at present rates of $384,402,246 less the total pro forma residential revenue at present rates of $249,466,945. See, Response to Interrogatory GA-2 Corrected, Attachment 2, pp. 3 and 65.

The Department found that the Company did not make the Application's revenue request PGA neutral. The ultimate impact of revenues from non-firm and ancillary activities on the PGA gas costs is net of applicable GET. Also, the non-residential revenue at present rates consist of all revenue from C&I customers including revenue from manufacturers who qualified for the 5% GET rebate. The total pro forma revenue at present rates should only be grossed up for the amount of MR that would be credited on industrial customers' bills. The Department recalculates the Company's allowed GET rate to be 4.1138% and reduces the proposed GET expense at present rates by $833,790. Additionally, due to SFA, the Department increases GET expense by $175,293, which is the SFA's additional revenue of $4,261,093 times the allowed GET rate of 4.1138%. Thus, the total decrease to the proposed GET expense at present rates is $658,493 ($833,790-$175,293) and the Department allows $16,026,840 ($16,685,337-$658,493).

2. Municipal Property Taxes

Southern proposed municipal property taxes of $5,388,821 for the rate year, which is an increase of $817,943 over the test year amount of $4,570,878. The pro forma property expense was calculated by starting with the latest available municipal property tax invoices for the fiscal year ended June 30, 2009. The 12 months ending June 30, 2008 actual net utility plant additions were used to develop municipal property taxes due and

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payable for the period July 1, 2009 through June 30, 2010. The Company stated that property taxes directly charged to Total Peaking Services, an affiliate company, were eliminated from the pro forma calculation. The Company also requested deferral accounting treatment on all future increases in personal property taxes caused by changes in valuation methodology by municipalities.

Southern claimed it is being forced by municipalities to change from a unit cost method to a Net Book Cost (NBC) methodology for declaring personal property. This change in municipal tax policy caused substantial increases in personal property tax expense because the NBC methodology increases declaration amounts. Changing from the unit cost method to the NBC method of declaring property can increase property tax expense for one town by hundreds of thousands of dollars. Southern stated that as a result of a change in methodology deferral accounting treatment of these uncontrollable, substantial and unanticipated changes in personal property tax expense will allow it to recover, or return, any variance from the level of expense allowed in base delivery rates. This treatment will ensure that ratepayers pay no more or less than the actual allowed personal property tax expense. Revenue Requirement PFT, pp. 45 and 46; Response to Interrogatory GA-2 Corrected, Attachment 2, p. 17; Schedules C-3.51 and WPC-3.51.

The Department maintains that Southern should continue to follow the existing property tax methodologies historically in place for a regulated utility. The proper administration of municipal property taxes requires the Company to take up any subsequent differences in property tax valuation with the appropriate municipality. The Department rejects Southern's proposal to establish a deferred account for future valuation differences.

The Department reviewed the Company's pro forma adjustment and determined that the proposed municipal property tax expense for the rate year is overstated. The Department's analysis of the proposed property tax adjustment based on the pro forma adjustment to the plant-in-service is below.

Line	Item	A Test Year	B=A-C Pro Forma Adjustment	C Rate Year
1	Plant-in-Service	$595,317,402	$24,507,239	$619,824,641
2	Reserve for Accumulated Depreciation	$243,398,334	$8,912,737	$252,311,071
3				
4	Net Plant-in-Service (Line 1-Line 2)	$351,919,068	$15,594,502	$367,513,570
5	Rate of Proposed Increase (Line 4, Column B/Column A)		4.43%	
6				
7	Property Tax	$4,507,878	$817,943	$5,388,821
8	Rate of Proposed Increase (Line 7, Column B/Column		17.89%	

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	A)			
9				
10	Ratio (Line 7/Line 4)	1.2988%	0.1674%	1.4663%
11	Rate of Proposed Increase (Line 10, Column B/Column A)		12.89%	

Schedules C-3.51 and WPC-3.51; Response to Interrogatory GA-2 Corrected, Attachment 2, pp. 7 and 10.
Based on the analysis above, the Company is requesting a 17.89% increase for municipal property taxes over the test year amount of $4,507,878. The increase in net plant-in-service is only 4.43% over the test year amount of $595,317,402. Linearly, the ratio of municipal property taxes to the net plant-in-service has to increase by 12.89% to justify the increase to test year amount proposed by the Company. There is insufficient evidence provided in this proceeding to substantiate an average increase to the mill rates of the municipalities in the Company's service territories between the test year and the rate year. Using the test year ratio of 1.2988%, the Department determines that the municipal property tax expense for the rate year is $4,773,426, which is the rate year net plant-in-service of $615,824,641 times 1.2988%. Therefore, the Department allows a municipal property tax expense of $4,773,426 for the rate year, which is $615,395 ($5,388,821 - $4,773,426) less than the proposed amount of $5,388,821.

3. Payroll Taxes

Southern proposed a payroll tax expense of $1,541,416 for the rate year, or an increase of $61,357 over the test year amount of $1,480,059. Schedule C-3.53.

OCC noted that the pro forma payroll tax expense was not adjusted despite Southern's proposed decrease to payroll expense. OCC incorporated the Company's adjustments to payroll and incentive compensation and its own proposed adjustments and determined a reduction of $163,033 to payroll taxes. OCC applied a composite rate of 7.55% to represent the employer's portion of the combined FICA and Medicare withholding tax rate. Brief, p. 112 and Schedule 6.

The Department agrees with OCC that the Company failed to adjust payroll taxes to reflect adjustments to pro forma payroll expense. Based on test year's payroll and payroll tax data on Schedules C-3.33 and C-3.53, the Department determines a composite payroll tax rate of 7.76% as indicated below:

Test Year Payroll Tax Expense	$ 1,919,367
Test Year Payroll Subtotal pre-capitalization	$25,417,729
Test Year Stock Option Expense	($ 40,304)
Test Year Total Payroll Expense pre-capitalization	$25,377,425
Test Year Payroll Tax Expense Rate	7.76%

The Department's adjustments to other payroll expense items are indicated in II.E.12. Payroll Expense - Excluding Executive. The Department's adjustment to payroll tax expense is shown as follows:

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Southern's Adjustments to Payroll Expense	$ 381,867
Department's Adjustment to Payroll Expense	$ 574,555
Total Adjustment to Payroll Expense	$ 956,422
Payroll tax percentage	X 0.0776
Payroll tax adjustment	$ 74,218

Based on the above, the Department reduces the Company's proposed rate year payroll tax expense by $74,218 and allows $1,467,198 ($1,541,416 - $74,218).

G. GROSS REVENUE CONVERSION FACTOR

The Department employs the Gross Revenue Conversion Factor (GRCF) to determine the change necessary in revenues to produce the required change in allowed operating income. This procedure is necessary because allowed operating income represents income after applicable taxes and other adjustments. Southern originally calculated a GRCF of 1.78097. Schedule A-2; RRP PFT, pp. 4 and 5. In its updated filing, the Company proposed a GRCF of 1.78992 that was calculated as shown below:

Revenue Change	100.00%
Less: GET Rate	4.34%
Less: Uncollectible Expense Rate	2.74%
	92.92%
Less: Connecticut Corporation Business Tax (7.50% times 92.9200%)	6.97%
	85.95%
Less: Federal Income Tax (35.0000% times 85.9500%)	30.08%
Net Income Percentage of Total Revenue	55.87%
Proposed GRCF (Reciprocal of 55.87%)	1.78992

Response to Interrogatory GA-2 Corrected, Attachment 2, p. 2

OCC recommended a GRCF of 1.78513 based on its recommended uncollectible rate of 2.49% versus the Company's proposed bad debt percentage of 2.74%. Brief, pp. 123 and 124.

In Section II.F.1. Gross Earnings Tax, the Department calculated and found that 4.1138% represents the allowed GET percentage. In Section II.E.9. Allowed Bad Debt Rate, the Department calculated that 1.9856% represents a reasonable non-hardship uncollectible percentage. Accordingly, the Department includes the allowed GET and uncollectible expense percentages into its calculation of the Company's allowed GRCF. The Department's calculation of the allowed GRCF is shown be- low:

Line		
1	Operating Revenue Change	100.0000%

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2	Less: Allowed GET Rate	4.1138%
3	Less: Allowed Uncollectible Rate	1.9856%
4	Income Before Income CCBT (Line 1- (Line 2+Line 3))	93.9006%
5	O&M Revenue Conversion Factor (Reciprocal of 93.9004%)	1.06496
6	Less CCBT (Line 4 X 7.5%)	7.0425%
7	Income Before Federal Income Tax (Line 4-Line 6)	86.8581%
8	Less Federal Income Taxes (35%) (Line 7 X 35%)	30.4003%
9	Operating Revenue Percentage (Line 7-Line 8)	56.4577%
10	Allowed GRCF for the Rate Year (Reciprocal of 56.4601%)	1.77124

Base on the calculation above, the Department determines that the allowed GRCF is 1.77124.

H. COST OF GAS AND GAS SUPPLY

In its Application, the Company provided data on the cost of gas, which included the test year, pro forma adjustments, and rate year dollar amounts as stated below:

Time Period	Firm Cost of Gas	Interruptible Cost of Gas	Total Cost of Gas
Test Year	$236,221,492	$34,602,014	$184,055,520
Pro forma Adj.	$ 41,376,901	$ 2,101,082	$ 46,256,179
Rate Year	$277,598,393	$32,501,832	$233,094,122

Schedule C-3.2.

The Company proposed an average firm cost of gas of $12.295 per Mcf for the rate year. This proposed cost of gas was based on a 30-day average New York NYMEX closing price of gas for each month of the rate year. A 30-day average is used to smooth out daily fluctuations in each of the monthly future's contracts. Marks, Rudiak and Therrien PFT, pp. 36-38; Schedule C-3.2.

On May 18, 2009, Southern updated its original cost of gas data and reduced the rate year firm and interruptible cost of gas by $43,624,161 for a revised total of $189,469,961. This represented a proposed cost of gas of $214,497,985 for firm and $17,574,848 for interruptible. Southern's updated rate year gas cost for firm customers is based on an average unit cost of $9.044 per Mcf. Response to Interrogatory GA-2, Supplemental #2, Schedule C-3.2.2.

The Department uses the most recent cost of gas to set the rate year cost of gas. Comparing the average cost of gas from the original filing of $11.50 Mcf to the updated cost of gas of $9.098 Mcf, ratepayers will save approximately $2.40 per Mcf. The reduction in the cost of gas reduces the carrying cost of gas associated with storage gas. Also, due to SFA, the Department increases total pro forma gas costs by $2,186,834.

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I. DECOUPLING / SSC TRUE-UP

1. Decoupling

Decoupling refers to severing (decoupling) the link between a company's recovery of the distribution revenues approved by the Department in a rate application and the unpredictable volume of gas sales actually experienced following the implementation of new rates. If actual sales volumes exceed forecasted sales used to design rates, then actual revenues will exceed Department approved revenues, to the financial benefit of the company. Conversely, a shortfall in sales equates to a shortfall in revenues received by a company. Fundamentally, this misalignment of actually billed versus Department allowed revenues exists for all utilities that recover short-term fixed costs through any volumetric rate design. Volumetric rates continue to be used extensively to design Connecticut utility rates. The legislature addressed this issue in § 107 of PA 07-242 (Act) by requiring the Department to decouple gas and electric distribution revenues from sales volumes through one or more of the following strategies.
1. A mechanism that adjusts actual distribution revenues to allowed revenues.
2. Rate design changes that increase fixed distribution charges.
3. A sales adjustment clause, rate design changes that increase the amount of revenue recovered through fixed distribution charges, or both.

The Department is also required to consider the impact of decoupling on a company's ROE and make necessary adjustments thereto.

In the instant case, the Company proposed three decoupling strategies that fully decouple the Company's sales volume from its revenues.
1. A revenue true-up mechanism.
2. Increases in fixed customer charges.
3. Continuation of recently approved declining block volumetric rate structures.
Therrien, Simpson PFT, p. 7.

The revenue true-up mechanism is discussed here. Customer charges and rate structures are addressed in Section II.K. Rate Design.

The Company considers its **decoupling** proposal as "quid pro quo" ratemaking treatment that would allow it to enhance its commitment to conservation programs without hurting itself financially. Therrien and Simpson PFT, p. 10. The Company would increase expenditures for the programs referenced in the Joint 2009 Natural Gas Conservation Program and monitor emerging high efficiency gas equipment for inclusion in such programs. Response to Interrogatory GA-294. **Decoupling** would also result in less frequent rate increase proceedings, saving time and expense for all parties. Therrien and Simpson PFT, p. 9. Current rate-making procedures no longer work because UPC has declined precipitously during recent history. Therrien and Simpson PFT, p. 8. Consequently, revenues obtained from new and existing customers during periods of declining UPC would not be sufficient to cover normal activities and afford the Company a reasonable opportunity to earn a fair rate of return. The Company's **decoupling** proposal would mimic current rate-setting procedures under a more stable UPC environment. Therrien and Simpson PFT, p. 14. Finally, the Company does not believe that any form of **decoupling** reduces business or financial **risk** for which equity investors require compensation. Consequently, no adjustment to ROE is required. Makholm PFT, p. 52.

The Company proposed modifying the existing CAM [FN3] to accommodate its usage-oriented decoupling true-up mechanism. Post-rate case actual monthly UPC would be trued-up to the monthly normalized UPC approved in the latest rate application. Each month's trued-up UPC would be multiplied by (1) the actual number of customers that month and (2) the volumetric rate [FN4] for the rate class in question. Interest, calculated at the Company's overall cost of money, would be added and the total trued-up revenue (debit or credit) would be booked. Annually, the accumulated net true-up for each rate class would be included in next year's CAM. The annual CAM would also include a deferral factor to recover prior year collection differences. [FN5]This new, expanded CAM (ECAM) would apply to

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all firm rate classes except Rate LGS, which the Company argues reflects too divergent a range in customer size to generate a meaningful class-average UPC. Rate LGS customers would continue under the existing CAM. Therrien and Heintz PFT, pp. 29 and 30.

> FN3. The current CAM recovers Department approved Company conservation expenditures from customers by means of a standalone, Company-wide volumetric charge added to customer bills. It also employs an annual deferral mechanism to true-up collections.
>
> FN4. June through September sales will be multiplied by the first block distribution rate. The second block rate will be used during the remaining months.
>
> FN5. Being a volumetric rate, the CAM will over or under collect its target amount whenever actual sales deviate from assumed sales used to derive the annual CAM charge.

The Company further explained that the proposed ECAM could result in a monthly credit adjustment to one rate class while another class experiences a debit adjustment. The proposed ECAM adjusts for all changes in sales while the added revenue from new customers is retained by the Company. Response to Interrogatory GA-310. Southern argues that new customer revenues must accrue to the Company as compensation for the costs of adding customers and to avoid creating a financial disincentive to adding customers. Response to Interrogatory GA-175.

OCC's position is that the Department should not approve the full **decoupling** proposed. But if a **decoupling** mechanism is approved, it should be an administratively simpler revenue **decoupling** model. Any **decoupling** reduces the net economic welfare of customers by shifting business **risks** from the utility and capital market to customers. Briden PFT, pp. 20 and 22. In turn, the reduced business **risk** should be rewarded by the capital markets in the form of a lower cost of capital, which translates into a lower revenue requirement. Further, customer revenue savings flowing from a lower ROE cannot adequately compensate customers for their assumption of **risk** under **decoupling**. The **risk** shifting effects of **decoupling** through rate design or a true-up mechanism are identical. Briden PFT, pp. 13-15. Finally, significant increases in rate design fixed cost recovery have already been made and that **decoupling** is not an effective means to promote conservation. Briden PFT, pp. 17-21.

AG believes that the Company's proposed full **decoupling** plan should be rejected in its entirety. The plan unfairly and improperly shifts the business **risk** of sales from the Company to customers. The **risk** should lie with the Company, whose ROE provides a cushion against fluctuations in sales. Brief, p. 16. AG argues that **decoupling** actually creates a disincentive for customers to pursue conservation and load management programs by denying the full bill reduction benefits of their conservational efforts. If the Department does approve **decoupling**, it should be a simple revenue tracker with a substantial reduction in ROE of at least 100 basis points. Further, a deadband, wherein 100% of the first 100 basis points of overearnings are returned to customers with a 50/50 sharing thereafter, should be implemented and on a trial-only basis. Brief, pp. 17 and 18.

ENE supports full decoupling and believes the Company should receive the full benefit of adding new customers. But unlike the Company's proposal, ENE prefers a revenue per customer (RPC) decoupling mechanism for all firm rate classes. According to ENE, a RPC approach would eliminate the need to choose a distribution block rate to calculate the revenue effect of a change in UPC. Also, basing the revenue-oriented decoupling true-up on a per customer basis would automatically credit the Company with new customer revenues. ENE believes that Rate LGS should be included in the Company's RPC as well. Leaving Rate LGS outside the true-up is not consistent with the language or intent of the Act. Brief, pp. 1-4.

The Department agrees with OCC and AG. The Company's full **decoupling** proposal compensates the Company for any type of reduction in consumption, such as warmer weather, customer loss, a deteriorating economy as well as permanent and price-induced conserva-

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tion. The very large **risk** of revenue instability is shifted from the Company to the customer. Theoretically **decoupling** would benefit customers by providing bill credits during colder than normal periods, but the Company's firsthand empirical experience with the WNA belies this potential. On average, customers were at **risk** for $2.9 million during the WNA years for weather only fluctuations. Add to this a continuing loss in UPC as predicted by the Company plus the uncertainty of a faltering economy and customers, conservatively, are at **risk** for $4 to $6 million of annual revenue shortfall.

It will require at least a 100 basis point reduction in ROE (approximately a $4 million reduction in revenue) to provide customers with commensurate **risk** compensation. While **decoupling** can be expected, *a priori,* to reduce the frequency of rate applications and associated expense, the Company has not proffered any stay-out proposal. The enlarged conservation expenditures that the Company points to as the **decoupling** quid pro quo, will be paid for by ratepayers, who will also experience upward pressure on rates as UPC declines further. The Company's full **decoupling** proposal guarantees a revenue stream while providing the Company the freedom to file a rate application at will. Based on the aforementioned, the Company's full **decoupling** proposal is denied.

The Department chooses to satisfy the Act by means of rate design. Since the adoption of the COSS standard in 2000, the Department aggressively supported increases in fixed distribution rate designs, including the adoption of 100% cost-based customer and demand charges. In the instant case, customer and demand charges are being increased by the Department even as the overall level of proposed revenue is reduced. Earlier approved declining block rate structures are continued and the proposed volumetric Sales Services Charge (SSC) and Transportation Services Charge (TSC) are being converted to demand charges. Also, the Company's existing CAM, which compensates the Company for sales reductions from Company sponsored conservation programs, will continue going forward. Existing, time-tested rate-setting principles afford Connecticut gas utilities ample opportunity to provide safe and efficient service while offering a reasonable opportunity to earn a fair rate of return on investment. The Department notes that the Company has filed only two rate applications since 1999, including the instant case. The existing process has worked well for the Company.

2. SSC True-up

The Company proposed the establishment of a supplemental supply cost reconciliation mechanism (SSCRM). The Company defined SSCRM as consisting of three main items affected by the cost of gas: (1) commodity-related uncollectible expense; (2) gas inventory carrying charges; and (3) gas working capital. The proposed reconciliation mechanism or true-up would update the fixed revenue requirement established for each item in the instant rate case to reflect future actual expenses through a line-item bill adjustment mechanism similar to the existing CAM. The detailed mechanics of the true-up procedure were initially agreed to by Connecticut's three gas utilities in the Cost Allocation Decision. Marks, Rudiak, Therrien PFT, pp. 38 and 39.

The Department addressed this issue in the Cost Allocation Decision and declined to implement a SSC true-up. The Department sees nothing new that warrants a change in its earlier position. Therefore, the Company's proposed SSCRM true-up is denied.

J. COST OF SERVICE STUDY

In general, a cost of service study (COSS) is a mathematical business model that systematically assigns cost responsibility among customer classes for the assets and expenses incurred by a local distribution company (LDC) to serve customers. Since the COSS culminates in summarizing customer, energy, demand and total costs by customer class, it is an invaluable tool for documenting equity and establishing revenue requirements and tariff charges by customer class.

In developing its COSS, the Company followed extensive cost allocation and apportionment rules established in the Decision dated August 9, 2000 in Docket No. 99-03-28,DPUC Review of Natural Gas Companies

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Cost of Service Study Methodologies and in the Cost Allocation Decision. All revenue and expense data used in the COSS replicates the same data used in the Company's proposed accounting and financial exhibits. Supporting workpapers represent test year data drawn from Company books and records. Therrien, Heintz PFT, p. 12. The Company's revised COSS included modest adjustments for minor discrepancies that came to light during hearings. Response to Interrogatory GA-2, Supplement No. 2.

OCC was concerned with the mechanics of the COSS and the reliance on COSS results as it influences rate design. OCC cautioned the Department not to become overly reliant on COSS results, which may prove questionable in a contracting economy. They also recommended that uncollectible expense be allocated among rate classes volumetrically. Brief, pp. 182 and 183.

While the Department finds that the Company complied correctly with the vast majority of COSS allocation rules, several issues are discussed below for clarity. The question of allocating cost responsibility for uncollectible expense has been raised many times before. In each case, the Department has reaffirmed the existing allocation methodology, and hereby does so again. The logic and mechanics of the Company's revised COSS as filed in the response to Interrogatory GA-2, Supplement No. 2, is approved, except where noted below.

1. FT Working Capital

The Company incorrectly calculated FT working capital in its original COSS filing. Working capital on purchased gas demand costs was allocated between FT and sales customers on the basis of each group's relative merchant-based peak day demand. Of the total gas demand working capital of $7,152,399, $1,344,096 or 18.65% was assigned to FT and $5,818,304 or 81.35% to sales. These incorrectly assigned amounts were then allocated correctly among customer classes based on each classes merchant-based peak day demand. Response to Interrogatory GA-283.

The Department wants to ensure that the LDCs calculate demand cost working capital in accordance with the directives established in the Cost Allocation Decision. The main difference is the way in which cost responsibility is initially split between FT and sales customers. The Cost Allocation Decision stated that FT's shifted demand costs minus capacity release is the basis for assigning demand working capital to FT customers. These two values are found in the Company's latest shifted cost calculation filed in accordance with Order No. 2 of the Cost Allocation Decision. In the instant case, FT's demand cost working capital is defined as follows:

Shifted Demand Costs	$8,790,257
Minus Capacity Release	897,246
Equals FT Basis	7,893,011
FT Basis Average Day	21,625
Proposed Lead/Lag Days	52.37
FT Demand Working Capital	$1,132,501

Response to Interrogatory GA-283.
This approach assigns the same total working capital amount of $7,152,399 slightly differently: 1,132,501 or 15.83% is assigned to FT, while $6,019,898 or 84.17% is assigned to sales. While the dollar impact is minimal, the Company is directed to adopt this approach in its supplemental and future COSS filings.

2. Equal Merchant, Distribution Rate of Returns

The Company's initial COSS development of the SSC and TSC set the return earned on all merchant assets for all firm rate classes equal to the proposed system-aver-

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age ROR. The Company adjusted its cost assignment methodology such that all merchant and distribution rate base items contribute the same ROR as the rate class in question. Since the resultant change in SSC or TSC revenue was negated by an offsetting change in overall distribution revenues, proposed class-level RORs did not change. Response to Interrogatory GA-303.

The Department believes that earning the same class-level ROR from all assets within a class, whether a merchant or distribution component, enhances customer equity by insuring all customers are assigned costs in accordance with similar asset utilization. The Company is directed to file its compliance COSS using equal merchant and distribution RORs within each rate class. The Department intends that the Company file its initial COSS and SSC/TSC rate proposal in future rate applications using equal merchant and distribution RORs as ordered here.

3. 100% COSS Demand Charge

The Company's initial filing of demand charges was technically confusing. The derivation of class specific distribution demand costs were calculated correctly within the COSS. However, summary costs were divided by demand billing units when calculating class-specific demand charges used in revenue proof exhibits. Schedule E-6, COSS, Exhibit 5; Schedule E-3.5.

The Department believes that demand charges should be derived using the demand units that constitute the demand allocator used within the COSS, which typically is different than pro forma demand billing units. This COSS-derived demand rate would then be applied to billing units to calculate demand charge revenues. This approach carries COSS derived demand charges forward to revenue exhibits without alteration, save possible GET, making the statement "100% COSS rates" technically accurate. The Department intends for the Company to use this convention in its supplemental and future COSS filings as well as in the revenue proof Exhibit VI worksheet, which provides the 100% cost-based rates.

K. RATE DESIGN

1. Methodology

Southern proposed to assign a firm pro forma revenue requirement to firm rate classes using the COSS as a guide. Its objective is to collect rates in a fashion that more closely mirrors the way its costs are incurred as well as moving the ROR from each rate class closer to the system-average ROR. This action reduces subsidies between rate classes as well as within a particular rate class and provides more accurate price signals to customers concerning the cost of gas distribution service. The Company stated that it seeks to build upon the rate design approved in the Rate Design Decision. However, due to consideration of rate continuity and customer rate impacts, the Company is not proposing to completely move each class ROR equal to the system-average ROR or to implement pure COSS-based rates. Therrien and Heintz PFT, pp. 3 and 4.

Southern's distribution costs are mostly fixed and the short-run costs of providing distribution service are largely unaffected by changes in delivery volumes and/or peak demand. The Company believes these fixed costs should be recovered through rates that produce relatively constant revenues, such as the monthly customer charge, demand charge, and in the head block delivery charge. Accordingly, Southern proposed to recover a larger portion of its fixed distribution costs from increased customer charges for all rate classes and increased demand charges from the applicable rate classes in an attempt to better align its revenue recovery with its cost to serve its customers. Id. The proposed volumetric charges are the result of a combination of COSS considerations, movement towards more equalized rates of return among the rate classes, and bill impact considerations. Therrien and Heintz PFT, p. 19. Southern's proposed head and tail block breakpoints remain unchanged from those approved in the Rate Design Decision. A review of bill frequencies supports the continued use of these breakpoints. Id.

OCC requested that the Department take into consideration the overall business and economic environment,

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which limits the ability of consumers to pay ever increasing rates. First, OCC cautions that the results of the COSS may be questionable in a contracting economy. Second, the recent volatility of natural gas prices requires extreme caution in evaluating the reasonableness of the bill impacts from Southern's proposed rates. Third, with the extreme changes in rate design implemented on November 1, 2008 pursuant to the Rate Design Decision, there is no need to go to extremes in this case. According to OCC, if there was ever a case that called for the application of the rate design doctrine of rate stability, it is this case. As such, OCC recommends that the drop from the head to the tail block delivery charges be no more than 30%. Further, revenues should be allocated in such a way that all customers in all rate classes be treated evenly with regard to any increases/decreases. Brief, pp. 182 and 183.

In general, the Department has many of the same rate design goals as the Company. Proper revenue allocation between rate classes and increased fixed cost recovery help to minimize existing inter-class as well as intra-class subsidization. The Department has historically used rate design as a means to better provide revenue stability to the Company. This is especially evident in the more recent rate design Decisions issued in the last eight years. For example, the Department approved a $4.75 increase in the Customer Charge for Rate RSH, from $8.25 to $13.00, an increase of approximately 58%. See, Rate Design Decision. Despite the overall revenue requirement decrease approved herein, the Department continues to increase fixed charges across all rate classes, which satisfies decoupling of sales from revenue as required by Public Act 07-242 § 107.

Nonetheless, the Department agrees with OCC that rate stability is critical in this case. It is essential to consider customer impact, both in terms of individual rate components and most importantly as function of the total bill. First, many customers have experienced two substantial rate amendments since January 2006. As a result of the Amended Settlement Agreement approved in the Decision dated December 28, 2005 in Docket No. 05-03-17PH01,Application of The Southern Connecticut Gas Company for a Rate Increase - Revenue Requirements (2005 Decision), Southern's volumetric delivery charges were increased across-the-board on January 1, 2006. Once the rate design was finalized by the Rate Design Decision, the Department approved substantial increases to most fixed charges and allowed the Company to implement a declining block rate structure. Given the timing of the instant case, the Department is concerned about rate stability because less than one year has passed since the Company's most recent rates went into effect. The Department will address its concerns with various aspects of Southern's rate design proposal for each rate class individually rather than using a rule of thumb approach.

The Department finds that certain adjustments to the Company's revenue requirements in the instant case will require significant changes to the proposed class revenue allocations and proposed charges. Therefore, Southern will be directed to file a final rate design plan (Rate Design Plan) to the Department reflecting the revenue requirement level approved in the instant Decision. The Rate Design Plan shall include a COSS, revenue proof exhibits and a bill impact analysis. The Department will provide guidelines below for allocating rate class revenue and the basis for determining certain charges including customer and/or demand charges. To generate the approved revenue, an adjustment to the volumetric delivery charges may be necessary. The Department agrees with the Company that the current block breakpoints remain reasonable. In adjusting delivery charges for rate classes with dual blocks, Southern will allocate any adjustments in such a way as to reduce the differential between the head block delivery charge and the tail block delivery charge, depending on whether an increase or a decrease to the delivery charge is required. The Department used this allocation method in the past and found it to be fair and not unduly burdensome to either high or low use customers. To the extent there are any unintended adverse bill impacts resulting from the general rate design directives given by the Department, proposed modifications in the Rate Design Plan may be considered.

2. Revenue Allocation

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Proposed revenues were allocated by the Company among rate classes based on a balance among several guidelines and criteria that relate to the design of utility rates. The criteria considered by the Company in determining revenue allocations include: (a) COSS results; (b) class contribution to present revenue levels; (c) customer impacts; and (d) the competitive market and general economic environment. Therrien and Heintz PFT, pp. 13 and 14. In general, rate classes with RORs above the system average were assigned a lower percentage increase than classes with RORs that were below the system average. These adjustments reduce or eliminate interclass subsidies and provide charges to customers that more closely reflect their cost to serve. Present and proposed rate class revenues and associated RORs for Southern are presented in the following table.

Total Revenue Requirement

Rate Class	Present Revenue	Present ROR	Proposed Revenue	Proposed ROR
RSG	$15,082,475	0.63%	$17,316,690	3.36%
RSH	$222,022,229	5.98%	$245,094,141	10.27%
RMDS	$12,366,570	7.92%	$13,053,444	10.86%
SGS	$30,951,377	2.38%	$36,193,975	6.77%
GS	$25,342,684	4.97%	$28,406,279	10.21%
LGS	$44,692,233	21.39%	$44,568,053	23.75%
Other	($250,626)	-	($246,331)	-
Firm Revenue Requirement	$350,206,942	6.47%	$384,386,251	10.51%
Special Contracts	$16,504,404	-	$16,504,404	-
Non-firm revenues and other	$17,690,900	-	$17,690,900	-
Total	$384,402,246	6.15%	$418,581,555	10.09%

Response to Interrogatory GA-2 Supplement 1, Attachment 1, Exhibit I.

For both Residential Service General (Rate RSG) and Rate SGS classes, the present RORs are significantly below the system average. The proposed ROR for Rate RSH, General Service (Rate GS), and Rate RMDS are moderately above the system average. The class revenue proposal for Rate LGS is significantly above the system average ROR. Southern proposed to increase the revenue allocations for Rate RSG and Rate RSH by 14.81% and 10.39%, respectively. The largest increase of 16.94% in total revenues is proposed for Rate SGS as a result of the reassignment of larger use customers in that class to Rates GS and LGS. The revenue increase assigned to Rate LGS shows a slight decrease of 0.28%. Id.

Although the Company stated it seeks to build upon the approved rate design from the Rate Design Decision, the Department finds that the proposed rate design is counterproductive to the progress made in that proceeding where half of the firm rate classes were within 1% of the system average ROR. The Department also approved a rate class ROR of less than 19.50% for Rate LGS. Increasing the proposed class revenue for Rate LGS to 23.75% reintroduces much of the cross-subsidies that previously existed among firm rate classes. Therefore, the Department directs the Company to decrease the proposed revenue allocation for Rate LGS in the Rate Design Plan such that the rate class ROR will continue to move toward the system average ROR. The

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remaining firm rate classes should continue to move toward the system average ROR as well.

As the final revenue figure will need to be reallocated to each rate class, the Department does not have the appropriate COSS information to approve actual rate class revenue; but can approve or provide guidance with respect to the rate class ROR. The Department approves the proposed ROR of 3.36% for Rate RSG. Although the instant Decision results in an overall rate decrease, revenue responsibility for this rate class should not be reduced as, historically, it has been heavily subsidized. The proposed class ROR for Rate RSH will be lowered to no more than the system average ROR approved herein. For the remaining rate classes, the proposed system average should be reasonably similar to the approved class ROR's relationship to the system average ROR from the Rate Design Decision, to the extent that this does not result in rate shock for any of these particular classes. The Department is concerned about the recent rate impact of Rate SGS resulting from the migration of large customers from this class. Therefore, any changes to this class should be modest. The Company will be directed to resubmit its class revenue allocations for Department approval as part of its Rate Design Plan.

3. Supply Charge

The Company set the supply charges at full COSS levels for all firm sales classes. Supply Charges are for illustrative purposes only, as gas costs are now recovered solely through the PGA. Therrien and Heintz PFT, p. 21.

The Department agrees with setting full COSS supply rates for each rate class, since this allocation methodology is consistent with prescribed PGA procedures. Bill comparisons at proposed and final rates in the instant case will best replicate actual bills that are calculated using PGA supply rates.

4. SSC/TSC

The Company proposed a volumetric SSC and TSC for all firm customer classes. Schedule E-3.5. As a general principle, the Company stated that it would not be opposed to establishing SSC and TSC demand charges for rate classes with a transportation service option (Rates RMDS, SGS, GS and LGS) because they already have a distribution demand charge. Nonetheless, the Company is not advocating for demand charges at this time. Southern is concerned about the effect of bill impacts, particularly for smaller customers. Response to Interrogatory GA-385. The Company did agree to implement SSCs and TSCs that were either 100% demand or commodity. Tr. 4/13/09, pp. 625 and 626.

The Department believes that equal SSC and TSC demand charges should be implemented for each of the three C&I rate classes. The analysis done in response to Interrogatory GA-385, which gave the Company concern over bill impacts and potential customer shift, is not representative of the situation that exists under final rates in the instant case. First, this interrogatory assumes Company proposed costs and ROR. Second, the analysis reflects the proposed full cost assignment of SSC and TSC costs among rate classes. In contrast, the instant Decision reflects a noticeably different set of costs, ROR and SSC-TSC COSS assignment among rate classes. The Company is directed to allocate SSC and TSC costs among C&I rate classes using the appropriate demand and commodity allocators to arrive at the correct revenue requirement for each rate class. All assets within a class will provide the same ROR as the rate class in question. The total class revenue requirement for both SSC and TSC will then be divided by the combined sales and FT peak demand to arrive at an equal SSC and TSC demand charge for each rate class. Rate RMDS will employ a separate volumetric SSC and TSC, while Rates RSG and RSH will employ volumetric SSC only. The Department believes that the introduction of a demand-based SSC and TSC satisfies the decoupling pursuant to Public Act 07-242 §107, while stabilizing gross margin recovery for the Company.

5. Residential Service Rates

Southern proposed to move toward more cost-based rates by increasing customer charges for all of its firm rate classes and adjust the demand charge for Rate RM-

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DS. Therrien and Heintz PFT, p. 15. The proposed 100% COSS based customer and demand unit rates are as follows:

Rate	Customer	Demand
RSG	$49.11	-
RSH	$50.40	-
RMDS	$179.80	$1.3020

Response to Interrogatory GA-2 Supplement 1, Attachment 1, Exhibit VI.
The Company stated that the current customer charges for the residential rate classes collect less than one-third of the actual customer costs. Customer costs not collected through a customer charge but rather through a volumetric distribution charge send improper price signals and erode based delivery revenue as a result of declining NUPC and changes in weather. Therrien and Heintz PFT, p. 7.

a. Residential General

Based on the proposed revenue of $17,316,690, Southern proposed the following charges for Rate RSG: (a) a monthly Customer Charge of $19.75, an increase of $4.75 over the current charge of $15.00; (b) a single block Delivery Charge of $1.1500 per ccf, a slight increase over the current charge of $1.0928 per ccf; (c) a Supply Charge of $0.8317 per ccf; and (d) a SSC of $0.0144 per ccf. Response to Interrogatory GA-2 Supplement 1, Attachment 1, Exhibit V.

In the Rate Design Decision, the Department approved a class ROR of approximately 3.0% for Rate RSG. As stated above, the Department approves maintaining the Company's proposed class average ROR of 3.36% for Rate RSG. This slight increase in class ROR moves the rate class closer to the system average ROR while limiting the bill impact associated with increased revenue responsibility for the rate class. Given the recent increases in revenue allocation and fixed charges for the Rate RSG class, the Department finds the proposed Customer Charge of $19.75 far too aggressive. The Department approves a Customer Charge of $17.00, a more modest increase of $2.00 over Southern's present Customer Charge of $15.00. This Customer Charge represents approximately 35% of the unit cost of $49.11 derived by the COSS. Further, the approved Customer Charge increases the Company's fixed cost recovery by approximately $591,044 (295,522 bills x $2.00). The Department believes that such an increase is necessary to recover fixed costs from low volume customers. The proposed Delivery Charge of $1.1500 per ccf will be adjusted to recover the allowed revenue for the Rate RSG class. The SSC shall be calculated in accordance with Section II.K.4. SSC/TSC, above.

b. Residential Heating

For Rate RSH, Southern proposed a monthly Customer Charge of $18.50, an increase of $5.50 over the current Customer Charge of $13.00. The proposed head block Delivery Charge was set at $1.0595 per ccf in the attempt to collect the remaining customer related charges not recovered through the monthly Customer Charge. Bill considerations also factored into Southern's proposed head block Delivery Charge. The proposed tail block Delivery Charge was set at $0.3995, a sufficient level to collect the remaining revenue requirement for the customer class not collected in the Customer Charge and/or head block Delivery Charge. Southern set the Supply Charge at $0.9868 per ccf and the SSC at $0.0783 per ccf. Southern's proposals for Rate RSH results in an annual revenue recovery of $245,094,141, an increase of 10.39% over present revenues. Response to Interrogatory GA-2 Supplement 1, Exhibits I and V.

The Department believes that Southern's proposed Rate RSH Customer Charge of $18.50 is excessive and

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would compromise rate stability for its largest class of customers. The proposed charge would result in an increase of $10.25 over less than a one-year period. Prior to the Rate Design Decision, the approved Customer Charge was $8.25. Because it had not been increased in many years, the Department allowed Southern to increase it by $4.75, or approximately 58%. Given the large increase in the Rate RSH Customer Charge approved in the Rate Design Decision, the Department believes a charge of $14.00 is more reasonable. The approved Customer Charge represents approximately 28% of the unit cost of $50.40 derived by the COSS. Further, it increases the Company's fixed cost recovery by approximately $1,595,928 (1,595,928 bills x $1.00). The Company will adjust its Delivery Charges to collect the remaining revenue allocation for Rate RGS class for Department approval in the Rate Design Plan. The SSC will be calculated in accordance with Section II.K.4. SSC/TSC, above.

c. Residential Multi-Dwelling

Southern's proposal for Rate RMDS results in an annual revenue recovery of $13,053,444. Southern proposed the following charges for Rate RMDS: (a) a monthly Customer Charge of $45.00, an increase of $10.00 over the current charge of $35.00; (b) Demand Charge of $0.4000 per ccf of demand, an increase of $0.3000 over the current $0.1000 Demand Charge; (c) declining block Delivery Charge head block of $0.3577 per ccf, and $0.1280 for tail block; (d) a Supply Charge of $0.9176 per ccf; (e) a SSC of $0.0844 per ccf; and (f) a TSC of $0.0802 per ccf. Response to Interrogatory GA-2 Supplement 1, Attachment 1, Exhibit V.

The Department approves Southern's proposed Customer Charge of $45.00. The approved Customer Charge represents approximately 25% of the unit cost of $179.80 derived by the COSS. A slightly more modest Demand Charge of $0.3000 is approved at this time as this charge only had been implemented for this class within the last year. Once the customers in this class have had more experience with Demand Charges to understand the extensive cost savings available from peak day conservation, the charge for this class can be moved closer to full cost. The approved Customer Charge and Demand Charge increase the Company's fixed cost recovery by approximately $392,226 [(12,352 bills x $10.00) + (1,343,532 ccf of demand x $0.20)]. The Company will adjust its Delivery Charges to collect any remaining revenue requirement for the class for Department approval in the Rate Design Plan. The SSC and TSC will be calculated in accordance with Section II.K.4. SSC/TSC, above.

The Company also proposed to deploy DDM devices for all Rate RMDS customers. These customers historically have not been required to have DDMs for two reasons. First, until recently, Rate RMDS customers were not subject to a Demand Charge. Second, multi-dwelling properties were often subject to vandalism. The new technology, wireless DDMS, require only a small attachment to the existing meter and no phone line connection. Therefore the risk of vandalism is significantly lower. Further, daily usage information would now be available to these customers to assist with peak day management. This provides another conservation opportunity to a wider group of customers. The Company estimates that it will have approximately 1,029 Rate RMDS customers during the rate year. The proposed monthly DDM charge of $6.91 is pure cost based and grossed up for Residential GRT. The Company-proposed pro forma revenues of $85,352 related to DDMs for Rate RMDS. Therrien and Heintz PFT, p. 20; Response to Interrogatory GA-2, Supplement 1, Attachment 1, Exhibit V

The Company discussed the pros and cons of its proposal to require DDMs for all Rate RMDS customers with the alternative of using the current 500 Mcf annual throughput standard used for C&I customers. Out of 948 total Rate RMDS customers, the Company identified 607 Rate RMDS customers, or approximately 64%, that used more than 500 Mcf on an annual basis during the test year. The Company stated that one of the drawbacks to having the DDM requirement only for customers that use more than 500 Mcf annually is the loss of daily consumption data for this group and the corresponding reduction in accuracy when setting their maximum daily quantity (MDQ) value. Another drawback is

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the additional administrative costs that would be required to create and maintain a Rate RMDS sub-group. The Company would need to identify the customers that would be exempt from the DDM requirement, monitor their exemption status at some regular frequency, and code them differently than other Rate RMDS customers for billing purposes. Additionally it would potentially require the addition and removal of DDM devices as customers exceed or fall below the 500 Mcf threshold. The positive result of the alternative is that it removes the expense of the DDM devices from the bills of the smallest customers in this rate class. Response to Interrogatory GA-309.

The Department extends to Rate RMDS its long standing DDM requirement for C&I customers with annual consumption greater than 500 Mcf. Customers above the annual threshold would benefit from daily consumption data as they have a greater ability to modify daily usage than those customers with lower annual consumption. For smaller customers, the possible cost savings from modifying peak day usage are much less than the costs associated with paying a monthly DDM charge. As with Rate SGS customers, the algorithm used by Southern to determine the peak day usage for these customers is sufficient. Other than coding these customers differently for billing purposes, the Department sees no material change in how the Company handles these customers administratively. The Department notes that prior to the elimination of C&I customer rate choice, Southern previously maintained a sub-group of Rate SGS customers that were not required to have DDMs.

As stated previously the Company identified that approximately 64% of its Rate RMDS customers used more than 500 Mcf on an annual basis during the test year. To calculate the pro forma adjustment, the Department applied the same factor to total pro forma customers to determine the approximate number of customers subject to a DDM requirement. Based on the Company's pro forma estimate of 1,029 Rate RMDS customers during the rate year, approximately 669 (1,029 x 0.65) of these customers can reasonably be expected to have a DDM requirement. The Department approves pro forma revenue in the amount of $55,473 (669 x 12 x $6.91) related to the Rate RMDS DDM requirement during the rate year. This represents a decrease of $29,879 from the Company proposed revenues of $85,352.

6. Commercial and Industrial Services

The Company proposed further increases to its C&I Customer Charges to move closer to cost-based rates. Southern's proposal sets the Rate LGS Customer Charge equal to the COSS unit rate. The Company also stated that its proposed Demand Charges are set at full COSS unit rates for both Rates GS and LGS. Therrien and Heintz PFT, p. 15. The proposed 100% COSS based customer and demand unit rates are as follows:

Rate	Customer	Demand
SGS	$97.73	$1.4948
GS	$190.71	$1.3345
LGS	$258.07	$1.3410

Response to Interrogatory GA-2 Supplement 1, Attachment 1, Exhibit VI.

The Department notes that the Demand Charge for Rates GS and the Customer Charge and Demand Charge for Rate LGS were set by the Company at less than the proposed 100% COSS-based rates. As discussed in Section II.K.4. SSC/TSC, the Department modified the Company's approach in favor of carrying the COSS derived demand charges forward to revenue exhibits without alteration, save gross receipts tax (GRT), making the statement "100% COSS rates" technically accurate.

a. Small General Service

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Southern's proposal for Rate SGS results in an annual revenue recovery of $36,193,975. Southern proposed the following charges for Rate SGS: (a) a monthly Customer Charge of $45.00, which is a $15.00 increase over its current charge of $30.00; (b) a Demand Charge of $0.4000, an increase of $0.1000 over the current charge of $0.3000; (c) declining block Delivery Charges of $0.7295 per ccf up to the first 100 ccf of usage, and $0.2950 for each ccf thereafter; (d) a Supply Charge of $1.0740 per ccf; (e) a SSC of $0.0498 per ccf; and (f) a TSC of $0.0771 per ccf. Response to Interrogatory GA-2 Supplement 1, Attachment 1, Exhibit V.

The Department remains concerned about the negative rate impact that resulted from the direct assignment of high volume C&I customers out of Rate SGS as previously approved in the Rate Design Decision. As a result, the Department believes that a $15.00 increase for the Customer Charge for Rate SGS is far too aggressive, and believes one third of the proposed increase is more appropriate at this time. The Department approves a Customer Charge of $35.00 for Rate SGS, which is just over 35% of the unit rate of $97.73 derived by the COSS. The proposed Demand Charge increase is modest, and therefore approved without modification. The approved Customer Charge and Demand Charge increases the Company's fixed cost recovery by approximately $1,031,257 [(174,476 bills x $5.00) + (1,588,766 ccf of demand x $0.10)]. The Company will adjust its Delivery Charges to collect any remaining revenue requirement for the Rate SGS class for Department approval in the Rate Design Plan. The SSC and TSC will be calculated in accordance with Section II.K.4. SSC/TSC, above.

b. General Service

Southern's proposal for Rate GS results in an annual revenue recovery of $28,406,279. Southern proposed the following charges for Rate GS: (a) a monthly Customer Charge of $75.00, which is an increase of $15.00 over its current charge of $60.00; (b) a Demand Charge of $1.3345, a slight increase from its current Demand Charge of $1.1790; (c) declining block Delivery Charges of $0.2950 per ccf up to the first 300 ccf of usage, and $0.0995 for each ccf thereafter; (d) a Supply Charge of $0.9340 per ccf; (e) a SSC of $0.0682 per ccf; and (f) a TSC of $0.0784 per ccf. Response to Interrogatory GA-2 Supplement 1, Attachment 1, Exhibit V.

The proposed Rate GS Customer Charge of $75.00 is reasonable, and therefore approved. The approved Customer Charge represents approximately 40% of the unit cost of $190.71 derived by the COSS. The approved charge increases the Company's fixed cost recovery by approximately $483,345 (32,223 bills x $15.00). The Demand Charge shall be 100% cost-based as determined by the COSS submitted in support of the Rate Design Plan. The Company will adjust its Delivery Charges to collect any remaining revenue requirement for the Rate GS class for Department approval in the Rate Design Plan. The SSC and TSC will be calculated in accordance with Section II.K.4. SSC/TSC, above.

c. Large General Service

Southern's proposal for Rate LGS results in an annual revenue recovery of $44,568,053. Southern proposed the following charges for Rate LGS: (a) a monthly Customer Charge of $251.00, which is an increase of $58.00 from its current charge of $193.00; (b) a Demand Charge of $1.3410, an increase from its current charge of $1.1875; (c) declining block Delivery Charges of $0.1395 per ccf up to the first 5,000 ccf of usage, and $0.0385 for each ccf thereafter; (d) a Supply Charge of $0.7568 per ccf; (e) a SSC of $0.1377 per ccf; and (f) a TSC of $0.0826 per ccf. Response to Interrogatory GA-2, Supplement 1, Attachment 1, Exhibit V.

Southern's proposed class revenue for Rate LGS and resulting ROR of 23.75% remains significantly higher than the proposed system average ROR of 10.09%. It is the highest ROR of all the rate classes. Response to Interrogatory GA-2, Supplement 1, Attachment 1, Exhibit I. As previously discussed, the Department believes it is appropriate to reduce the proposed revenue allocation dramatically to reduce subsidization by this class. As it did in the Rate Design Decision, the Department approves a 100% cost-based Customer Charge and De-

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mand Charge as determined by the COSS submitted in support of the Rate Design Plan. The Company will adjust its Delivery Charges to collect any remaining revenue requirement for the Rate LGS class for Department approval in the Rate Design Plan. The SSC and TSC will be calculated in accordance with Section II.K.4. SSC/TSC, above.

7. Summary of Rate Design Changes

The Department believes the approved charges herein builds upon the rate design approved in the Rate Design Decision. Rate class revenue responsibility will be assigned in a fashion that reduces cross-subsidies between rate classes to the extent possible. Further, the Department approved increases in fixed charges for all rate classes that are not already at 100% cost based reduces intra-class subsidies and increases fixed cost recovery by the Company. Yet to be quantified, customer and/or demand charges for Rates GS and LGS that will be set by the Company's COSS with its Rate Design Plan. Initial customer and demand charges approved in the instant Decision increase the Company's fixed cost recovery by approximately $4.1 million. Actual fixed cost recovery will not be known until the Company submits its proposed Rate Design Plan. Increased fixed charges fulfill the requirements of Public Act 07-242 § 107 by decoupling sales from revenue. The introduction of demand SSC and TSC also decouples sales from revenue while stabilizing gross margin recovery for the Company.

8. Weather Normalization Adjustment

The WNA is a rate mechanism that adjusts the non-gas portion of customers' bills to offset the influence of weather on those bills. If weather is warmer than normal, the adjustment is upward (customers are charged a higher unit non-gas charge); if weather is colder than normal, the adjustment is downward (customers are charged a lower unit non-gas charge). To date, Southern has been the only Connecticut LDC to be allowed a WNA mechanism.

Southern's WNA was established by the Decision dated December 1, 1993 in Docket No. 93-03-09,Application of The Southern Connecticut Gas Company to Increase Its Rates and Charges, as a result of a settlement agreement among the Company, Prosecutorial Division of the Department (Prosecutorial) and OCC. The Department accepted this aspect of the settlement on the belief that the WNA mechanism "... provides both revenue protections for the Company and bill moderation for customers."Decision, p. 8.

In the first rate case proceeding following the establishment of the WNA, the Department reviewed the merits of the WNA and decided to allow its continuation by Decision dated January 28, 2000, in Docket No. 99-04-18PH02,DPUC Review of The Southern Connecticut Gas Company's Rates and Charges (2000 Decision). However, Southern's authorized ROE was reduced by 25 basis points, from 10.96% to 10.71%, to account for the earnings stability provided by that mechanism. During that proceeding, the evidence showed that Southern had benefited significantly from the WNA. For the five-year period (1994-1998) that the WNA had been in effect, the Company averaged an ROE of 12.64% with the WNA, an increase of 85 basis points versus an 11.79% ROE without a WNA. The Department viewed the ROE effect as "an accident of history" because the 5-year WNA period included two of the warmest years of that century. The Department was of the belief that the ROE would be reduced in future years when weather approached normal over the long term. The Department stated that "the revenue flows produced by the WNA should average out over the 30-year cycle, which is the basis for the determination of normal weather."2000 Decision, pp. 69 and 70. The Department stated that it will continue to monitor the effects of the WNA on the Company and its ratepayers. 2000 Decision, p. 70.

During Southern's subsequent rate case proceeding, the Department sought to review the merits of continuing the WNA. However, in the 2005 Decision the WNA was continued as part of a settlement agreement among Southern, OCC, Prosecutorial, as well as Select Energy, Inc., and Amerada Hess Corporation. 2005 Decision, p. 13.

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In the instant case, Southern proposed to eliminate the WNA only in the event its proposed decoupling mechanism is approved. Therrien and Heintz PFT, p. 5. See, also Section II.I. Decoupling/SSC True-Up, above. Southern stated that theoretically, the WNA should serve as a volatility smoother for deviations from normal weather and be of equal benefit to the ratepayers and the Company. Administratively Noticed Docket No. 08-12-06, Tr. 3/24/09, p. 1418. Southern acknowledged, however, that to date the WNA had not equally benefited ratepayers and the Company. Id., p. 1420.Southern benefits significantly from the WNA, which is currently in its 16th year. During this time, Southern received a total of $43.6 million in net WNA revenue through March 2009. Ratepayers benefited in only three of those 15-plus years. Responses to Interrogatories GA-141 Supplement, Attachment; and GA-138 Supplement, Attachment. Further, the Company's ROE benefited significantly. The table below shows the Company's ROE with and without the WNA for each year the WNA was in effect.

Year	% ROE With WNA	% ROE Without WNA	Difference
1994	11.97%	12.05%	0.08%
1995	11.34%	9.79%	-1.55%
1996	12.38%	13.52%	1.14%
1997	12.35%	11.71%	-0.64%
1998	11.53%	8.19%	-3.34%
1999	12.46%	10.48%	-1.98%
2000	12.74%	12.28%	-0.46%
2001	15.05%	13.80%	-1.25%
2002	8.49%	6.40%	-2.09%
2003	10.44%	11.57%	1.13%
2004	10.84%	10.45%	-0.39%
2005	7.42%	7.05%	-0.37%
2006	7.04%	5.13%	-1.91%
2007	11.93%	10.98%	-0.95%
2008	11.27%	9.84%	-1.43%
Average	**11.15%**	**10.22%**	**-0.93%**

Response to Interrogatory GA-141, Attachment.
As indicated, the average ROE with the WNA was 11.15% versus 10.22% without a WNA, an increase of 93 basis points (11.15% - 10.22%).

Based on the WNA history, OCC believes that it is fatally flawed and overwhelmingly in favor of the Company and against ratepayers. Brief, p. 178. However, if OCC could be assured that the WNA would serve as a volatility smoother and equally provide benefits to ratepayers and the Company, then OCC would have no objection to its use and may even favor it. Id., p. 176.

The WNA has not performed as the Department had believed it would when its continuation was allowed in the 2000 Decision. To date, the WNA has been one-sided in favor of the Company. As stated earlier, the Department was of the belief that the ROE would be reduced in future years and that the revenue flows would average out over the 30-year normal weather period. The WNA is

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now half-way through the 30-year averaging period and neither has happened. The 85 basis point average bonus to the ROE has now increased to 93 basis points and the Company is nearly $44 million better off with the WNA than without. Further, what was deemed an "accident of history" by the Department in the 2000 Decision has actually continued on a trend of warmer than normal weather in 12 of the 15 years since the WNA was established. Unless the weather pattern turns colder than normal for the majority of the remaining years of the 30-year cycle, the revenue flows will have little or no opportunity to average-out, and the benefit between ratepayers and the Company will not equalize as expected. Because there is no guarantee that the current weather trend will reverse itself, the Department finds that continuing the WNA would not be in the public interest. Consequently, the Department hereby abolishes Southern's WNA. Effective with new rates, Southern is directed to cease applying the WNA to customer bills. The Department reserves for a future proceeding any determination regarding the historic operation and financial impact on the company and ratepayers of the WNA.

L. MAXIMUM DAILY QUANTITY

The MDQ measures a customer's peak day consumption and is used to allocate class specific Demand Charges to individual customers. In the Rate Design Decision, the Department concluded that Southern's tariffs were clear and unambiguous regarding the calculation of the MDQ. Further, it concluded that Southern was not calculating the MDQ accurately or in accordance with its tariffs. Rate Design Decision, p. 34.

The failure to calculate the MDQ accurately or in accordance with the Company's tariffs has ramifications for the instant rate case. When designing new rates, the Demand Charge listed on specific tariffs is multiplied by the aggregate billed MDQ to determine Demand Charge revenue. If billed MDQs are misstated in this calculation, then demand revenue is also misstated. The resultant error in demand revenue is then built into other tariff charges to collect the correct total revenue. When MDQs are billed incorrectly, all other customers are affected through their respective tariff components. Miscalculated MDQs result in an over or under collection of revenue by the Company. To gauge the scope of the problem identified in the Rate Design Decision, the Department ordered Southern to file a MDQ analysis in Order No. 20.Southern was directed to calculate the revenue it did not collect during the test year. Order No. 20 was not a complete list of all of the billing records issued during the test year. It did not include customer bills that were issued based on estimated reads. Tr. 4/21/09, pp. 2166-2185.

In the instant case, Southern included a proposed positive revenue adjustment of $102,020 for Demand Charges not collected. Using Southern's exhibits, the Department applied the average daily use test as described in the tariffs, which was in effect during the test year, customers would have seen higher bills. The excel spreadsheets included in the Order No. 20 submission included 220,000 separate lines of C&I billing records for the test year. Rudiak and Therrien PFT, p. 23.

Southern stated that the MDQ is based on a customer's peak day usage during the winter months and is used to determine the Demand Charge. A DDM is used to measure the peak day consumption. If the customer does not have a DDM in place, the highest average daily usage during the winter is used. In April, the Company performs an annual review of each customer's November through March consumption to determine the MDQ to be used for the May bill. This MDQ is held consistent for the next 12 months. Tr. 4/21/09, pp. 2166-2185. During the April review, the billing department downloads "all of the data" associated with each of the 17,000 C&I customers' billing data into one file. Then a rate analyst reviews and evaluates the consumption data, and checks for reasonableness and accuracy of the MDQs. Throughout the review, management typically checks the data using specific tests related to customer load factor and verifies whether the MDQ results are reasonable. At the end of the April review, management performs a comparison to the previous year's data to verify that the new MDQs are reasonable. Tr. 4/21/09, pp. 2166-2185.

Southern agreed that the Rates SGS, GS and LGS tariffs

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require all C&I customers to pay Demand Charges. Tr. 4/21/09, pp. 2166-2185. However, if a MDQ is not determined correctly, that customer will not pay a correct Demand Charge. The Company sent out 456 bills to Rates SGS (161), GS (195) and LGS (100) customers with a billed Demand Charge of one during the test year. Response to Interrogatory GA-390. The Company testified that it did not send out bills showing zero MDQs during the test year. Tr. 4/21/09, pp. 2166-2185.

A MDQ of one means that a customer used, at most, one unit of gas each day for the billing period. Though Rate SGS customers have no minimum annual usage requirement, the class average usage is 1,042 ccf. Assuming a constant load, an average Rate SGS customer would have at a minimum a 16 ccf MDQ. The corresponding minimum MDQ for Rate GS is 89 ccf and Rate LGS is 391. However a customer could reasonably be charged a MDQ and Demand Charge of one if that customer was a new account and did not have any previous consumption data for the November through March period. Further, a customer could be assigned a one MDQ if the April review demonstrated the preceding winter's consumption did not produce a MDQ greater then 1 ccf. If the MDQ is less then 1 ccf, the computer program will default to a one and leave the MDQ space on the bill blank. Consequently, the Demand Charge will also default to zero. Administrative Notice Docket No. 08-12-06, Tr. 3/24/09, pp. 1365-1369.

Southern provided an exhibit that showed 362 bills were issued to Rate LGS customers during the test year with MDQs that were less then the minimum MDQ described above. Of these bills, 318 had MDQs of 1 ccf of which 23 were sent to one customer with multiple premises. The exhibit shows that 57 of the 362 bills were to accounts that did not have DDMs. The bills indicated that DDMs were installed on 305 (362 - 57) meters between 1999 and 2001. The exhibit also showed that 50 Rate LGS bills, each with a billed MDQ of 22 ccf, were sent to one customer with multiple premises with DDMs installed during 1999. Of these 50 bills to the same customer, 12 had a very large monthly consumption and 38 had zero monthly consumption. Response to Interrogatory GA-390. There was no explanation why an operating DDM would not record an accurate MDQ.

Southern's exhibit also showed that it issued 562 bills during the test year that were less than the minimum average for the Rate GS customer class. Of these 562 bills, 195 were issued with a MDQ of 1 ccf and 104 bills were issued with MDQs between 2 and 4 ccf. The exhibit shows that 91 bills had DDMs installed between 1999 and 2001, 33 bills had DDMs installed between 2003 and 2005 and the remaining 113 customers had DDMs installed between 2007 and 2008. The exhibit also showed that 322 bills were issued during the test year that did not have a DDM installed. Finally, the exhibit shows that Southern issued 161 bills to Rate SGS customers with a zero MDQ and a zero Demand Charge. Of these 161 bills issued, 22 had DDMs installed during 1999 and 2000. Response to Interrogatory GA-390. There was no explanation why an operating DDM would not record an accurate MDQ.

Southern provided its criteria to determine whether a customer should take service under Rates SGS, GS or LGS. Customers are placed on a specific rate based on the customer's actual or reasonably anticipated consumption. Southern listed the specific consumption requirements as part of the Company's tariffed Rates GS and LGS. Response to Interrogatory OCC-207. According to the Company, its policy is to apply the customer charge as of the date the meter is turned on and the gas flow is available for the customer. The MDQ and Demand Charge should be applied to all C&I customers' bills as of the date the meter is turned on and the Customer Charge is applied. Tr. 4/21/09, pp. 2166-2185.

There are three types of C&I customers where inexplicably low MDQ readings are problematic. First, existing customers who have received service for over one year. Second, transfer customers who become the occupant of existing premises where the service and meter are already connected to the distribution system. However, if the premises were vacant during the winter prior to the April review there would not be any historical consumption data for that premises and the billing program would default to a MDQ of 1 ccf. During the next annual review the customer's consumption during the winter would be included in the consumption data and used to

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calculate the MDQ for the subsequent 12 month period. Administrative Notice Docket No. 08-12-06, Tr. 3/24/09, pp. 1372 and 1380; Tr. 4/21/09, pp. 2166-2185. Third, new customers who have never received service from the Company's distribution system. For these customers, Southern's sales and marketing department performs a Hurdle Rate analysis. This analysis includes estimated annual consumption and maximum hourly loads based on the customer's equipment, internal processes and hours of operation. The maximum hourly loads included in the Hurdle Rate analysis would be used by the engineering department to design the customer's service and would form the basis for the estimated MDQ until actual MDQ reads become available. Tr. 4/21/09, pp. 2166- 2185.

Southern testified that it used the data from Order No. 20 to calculate the revenue adjustments for the test year, pro forma, and rate year contained in the response to Interrogatory GA-390. That exhibit calculated a minimum class average MDQ by taking the minimum consumption included in the tariff for each of the relevant rate classes and dividing that number by 365 days. The exhibit then listed each of the C&I customers that did not meet this test. Then each of the MDQs, which were less than the minimum average, was replaced with the class average MDQ. This new MDQ was then multiplied by the appropriate rate for the class to equal the corresponding revenue adjustment. Southern's exhibit shows that 1,085 bills were issued that were less than the minimum MDQ as determined by the Department above. Of the bills issued with a MDQ of 1 ccf, 17.9% (195 / 1,085) were reasonably expected to Rate GS customers and 29.3% (318 / 1,085) Rate LGS customers. The exhibit also subdivided the respective rate classes into FT and sales categories. The exhibit estimates that the Company did not bill a total of $270,502 during the test year to C&I customers. Southern made adjustments in the pro forma revenues at present rates of $279,929 and at proposed rates of $318,529. Response to Interrogatory GA-390, pp. 21.

During the MDQ audit at its offices, the Department requested the Company submit more than 30 Hurdle Rate calculations to support their MDQ estimates. The Company submitted four. Response to Interrogatory GA-1 and ADRs 1-17. The Department calculated the total revenue that Southern should have billed during the test year using several methods. The most accurate method the Department could have used would be the sales and hourly loads for each customer included in the Hurdle Rate calculation. However, Southern testified that researching and providing the Hurdle Rate calculations for each customer with a zero or 1 ccf MDQ would have been an impossible task if it had Hurdle Rate calculations for these customers. If the Department were to use the Hurdle Rate calculations provided and extrapolate those to each customer class, the test year revenue adjustment would be between $429,000 and $1.38 million over the eight year period evidencing incorrect MDQ billings. The total revenue misallocation would be approximately $11 million. Interrogatory GA-392 required the Company to calculate a minimum class average MDQ based on the minimum consumption included in the tariff requirements for Rates GS and LGS and dividing that number by 365 days.

As a validity test, Southern compared those minimum class averages to each MDQ reported by the Company. The Company applied these to estimate the uncollected MDQ revenue during the test year to calculate its $270,502 test year revenue adjustment in the response to Interrogatory GA-390. This method seriously underestimates the test year MDQ revenue adjustment because it assumes a highly improbable 100 load factor. Over the eight-year period evidencing incorrect MDQ billing, the total misallocation would be approximately $2.16 million.

The Department accepts the Company's test year revenue adjustment of $270,502 despite its methodological infirmities. The Department finds it improbable that the Company was unaware of the scope and size of the MDQ issue for so long. The Company was imprudent. Therefore, the Department reduces the Company's ROE by 10 basis points because of imprudence. In arriving at the imprudence penalty, the Department considered alternative options. The failure to bill and collect Demand Charges from the under billed customers also affects other customers; all else held equal, if revenues from

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the under billed customers are not included in rate case sales projections, the effect of understated sales is increased rates. To acknowledge the unfairness to other customers that results from uneven application by the Company of its tariffs, the Department considered requiring shareholders to contribute further to peak demand conservation programs. Additionally, the Department considered the possibility that higher rates to other customers also leads to higher uncollectible balances, and therefore contemplated a downward adjustment to uncollectible balances. The Department assumes that 10 basis points equals approximately $400,000.

Southern explained that its Hurdle Rate model, defined as a "SCG Capital Investment Decision Model," is a discounted cash flow analysis over a 34-year period that is used to calculate the annual cash flow for potential new customers. Southern performs a Hurdle Rate calculation for each potential customer that contacts the Company regarding possible connection to the distribution system. If a Hurdle Rate calculation results in a positive cash flow over the standard 10-year payback period, the customer does not pay a contribution-in-aid-of-construction (CIAC). The payment of a CIAC by a customer brings the Hurdle Rate calculation back to a positive value. The model calculates the revenues based on the currently approved tariffs. A customer's anticipated annual consumption must recover the capital investment necessary for them to be connected to the distribution system. The model also includes the impact of taxes and deferred taxes on the revenue for that customer. Response to Interrogatory GA-97.

The Company provided an excel spreadsheet for a hypothetical potential residential customer anticipated to take service under Tariff Code-1 1c. The example of the hypothetical customer's specific characteristics included: the annual base and heating annual consumption, service and meter costs, customer's peak day, full year gross margin, load factor, annual revenue and annual cash flow and the net margin for commission. The working excel spreadsheet showed the depreciation rates used in the Hurdle Rate model. The model indicated the following time periods over which certain items were depreciated: mains over 34 years, services 17 years and meters 23 years. Response to Interrogatory GA-97, Attachment 1.

The Company presented different depreciation rates in the Hurdle Rate model than in the Depreciation Study. Tr. 4/14/09, pp. 867-880. The Hurdle Rate model assumes that there is consistent revenue over the entire period of 34 years. The Company provided an example of a Hurdle Rate calculation for a hypothetical Southern residential heating customer on Rate 1C in North Branford. See, Response to Interrogatory GA-97, Attachment 1. The Company's Hurdle Rate model included a salesman's commission rate for residential rate classes of 45% and 15% for C&I rate classes. Southern Hurdle Rate model shows Net Margins for Commissions related to the specific residential customer used in the model was $406 and a corresponding first year gross margin of $894. The model shows that the internal rate of return (IRR) is based on a first year's revenue, which was reduced by revenues for the salesman's commissions. Response to Interrogatory GA-97.

During the hearings, the Company was requested to provide a proposed revision to the Hurdle Rate model using the straight line method of depreciating the capital investments included in the model and not use accelerated depreciation for a residential heating customer. The Company did not provide a comparison of the accelerated depreciation versus the straight line depreciation. Late Filed Exhibit No. 115, Attachment 1 and 2. Since the Company did not provide a revised Hurdle Rate using the correct depreciation rates, the Department was unable to review and determine whether the current Hurdle Rate model is appropriate. The Company is directed to use only Department approved tariff terms and depreciation rates in its Hurdle Rate model.

The Department believes that its sampling of the Hurdle Rate model inputs does not comport with the Department's expected calculation of the CIAC. Therefore, the Department intends to audit the Company's Hurdle Rate model process.

M. NON-FIRM MARGIN SHARING

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The LDCs generate profits in the form of a NFM during the year by making sales utilizing seasonal excess pipeline capacity through on- and off-system sales, capacity release activities and optimization savings recoverable from the gas supply alliances or similar arrangements approved by the Department. The Department approves an annual NFM threshold for Southern based on the margins it is reasonably expected to earn from non-firm sales. The NFM achieved up to the threshold flows 100% to firm customers. The NFM earned in excess of the threshold is shared between Southern's ratepayers and shareholders at percentages of 86% and 14%, respectively, pursuant to Section G.3 of the Amended Settlement Agreement in the Company's last rate case proceeding.

In the instant case, Southern proposed no change to the NFM sharing percentages above the annual NFM Threshold. The Company stated that the current NFM sharing percentages provide the Company with the necessary incentive to maximize margins. Marks, Rudiak and Therrien PFT, p. 43. The Company believes that the current NFM sharing is an appropriate incentive to go beyond ongoing customer service, such as formulating monthly flex prices, tariff administration, managing curtailments, and other customer service functions through aggressive and creative NFM program administration. This includes significant marketing key account representation and support, as well as special contract negotiations. The Company also recognizes its obligations to maximize margins as a general premise and regulatory requirement given its funding of full cost of service through firm rates. Response to Interrogatory GA-369.

There has been considerable discussion in the past about the level of effort on the Company's part and the proper level of incentive the Company should be given to maximize NFM. The Company stated that up to 30-40% of these sales are attained with little administrative effort. The remaining 60% or so requires varying degrees of effort to attain, but mainly depend on the competitiveness of natural gas to alternative fuels. The last 5-10% of sales, in which the Company goes out to find new customers or new loads, is where a considerable amount of effort may be made. Docket No. 04-05-11,DPUC Generic Review of the Southern Methodology of Allocating Gas Costs, Response to Interrogatory GA-47; Tr. 1/25/05, pp. 790 and 791. However, the single biggest factor that affects the amount of margin generated is the spread between natural gas and oil, of which the Company has little to no control over. Docket No. 04-05-11, Tr. 1/25/05, pp. 797 and 798. This spread primarily influences how much volume interruptible customers will consume as well as the level of margin per each unit consumed. To the extent that the Company can pursue opportunities to bring new or additional interruptible load on the system, it is largely a function of the competitiveness of natural gas to alternative fuels. Further, sales volumes can be lost due to poor economic conditions, over which the Company also has little control.

While it has been difficult, at best, to determine the optimal level of necessary incentive, the Department finds that the incentive structure in place for many years has been much more generous than necessary to accomplish the goal of maximizing NFMs. The Company retained on average approximately $1.19 million in NFM annually for the last five years. Response to Interrogatory GA-369, Attachment 1. These generous incentives are at the detriment of ratepayers who pay for the system making these sales possible. The Decision dated August 12, 2005 in Docket No. 04-05-11 stated, in relevant part:

...margins above the threshold margin target will be shared with the LDCs at a lower rate than the existing rate for margins earned in excess of the target margin. Since the elimination of a target included in base rates completely eliminates the downside risk for the LDC from any specific target, a reduction in reward is appropriate.

Decision, p. 14.

Despite the decrease in its sharing percentage that resulted from the Settlement Agreement in Southern's last rate case, the Department finds there has been no reduction in reward to the Company in return for the risk that was shifted to ratepayers. Conversely, Southern received approximately $1.8 million in 2007, or $467,989 more than it earned in 2005. Response to Interrogatory

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GA-369, Attachment 1.

Admittedly, the current NFM mechanism in place has some inherent flaws. If the NFM threshold is forecasted too high and the Company believes it is unattainable, the Company has little incentive to maximize NFM regardless of where the sharing percentages are set. Further, the methodology in place for forecasting the annual NFM threshold is not forward looking, but rather, based on historical information. The Department believes an alternate NFM mechanism that starts with the very first sale is far more appropriate. Although the level of incentive will vary from year to year, some level of incentive will be achievable by the Company each and every year, and the incentives will be directly related to the actual NFM attained.

The Department hereby eliminates the annual threshold in the NFM sharing mechanism in favor of a lower sharing percentage from the very first dollar of NFM earned, rather than from a historical estimate of the future. Because there is no longer any risk to the Company for any level of NFM earned and the level of NFM achieved is largely a function of market conditions outside of Southern's efforts, a sharing percentage of 1% under the new mechanism is much more reasonable. Had this mechanism been in place during 2007, the Company would have received $176,505 ($17,650,552 x 1%) in shareholder incentives. Response to Interrogatory GA-396, Attachment 1. The Department believes that this is a much more reasonable incentive level. The new mechanism will provide some incentive level each and every year, more commensurate with the Company's activities, and less on market conditions.

Based on the above, the Department establishes a modified NFM mechanism in which Southern shall retain 1% of all NFM earned. The new NFM mechanism will go into effect on January 1, 2010 upon conclusion of the Company's current mechanism year, which is for calendar year 2009. As there will be no NFM threshold going forward, Southern will no longer need to file NFM testimony in a separate docketed proceeding as directed in the Interim Decision dated March 26, 2008 in Docket Nos. 07-04-01 and 07-10-01,DPUC Semi-Annual Investigation of the Purchased Gas Adjustment Clause Charges or Credits Filed by: Connecticut Natural Gas Corporation, The Southern Connecticut Gas Company, and Yankee Gas Services Company. Instead, the Company will file a report in the semi-annual PGA proceedings on the level of NFM earned monthly from each source of non-firm activity as well as the sharing levels between ratepayers and the Company's shareholders.

N. TARIFF CHANGES

1. Interruptible Service Commitment Period

Interruptible rates are established using value-of-service (VOS) pricing based on the alternate fuel source. Until recently, interruptible VOS prices were typically lower than firm rates. However, the extraordinary market conditions recently experienced in the energy markets have resulted in interruptible rates that were higher than firm service rates. The Company has two options under this scenario. It could charge below market VOS pricing to retain the customer on interruptible service. Or it could provide the customer with the applicable firm service, as well as educate the customer as to service obligations under firm and interruptible service and leave the decision to the customer. Since December 2007, Southern has had several interruptible customers switch to firm service to take advantage of the recent economically attractive rates. Therrien and Heintz PFT, p. 28.

Because the Company maintains supplier of last resort (SOLR) obligations for its firm rate classes, it takes on additional SOLR obligations when interruptible customers switch to firm service, even if only for one year. As a result of the interruptible to firm switches, the Company has taken on approximately 5,000 Mcf in additional peak day load in the last two years. Tr. 5/7/09, p. 2290. The Company notes that obtaining additional capacity in the constrained Northeast market is no easy task. Incremental supply, if available, is costly and requires very long contractual arrangements, perhaps ten to fifteen years. This creates a potential cost shifting of these capacity costs to firm customers in the event the customer switches back to interruptible service. Brief, p. 139.

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To eliminate potential cost shifting and allow the Company to efficiently plan for supply, Southern proposes to modify its Manual Interruptible Service (Rate IS) tariff. This modification would require any customer switching to firm service to remain on the assigned firm rate for a minimum of three years. Therrien and Heintz PFT, p. 28. Rate IS allows the Company, in its sole discretion, to deem a customer ineligible to transfer from interruptible to firm service if doing so would jeopardize the Company's ability to balance its load. The Company evaluates each request based on its ability to serve the customer considering its interstate transportation, storage and supply position, and accommodates such requests whenever possible. Firm service tariffs contain a term of service provision that requires the customer to fulfill 12 months of continuous service under either its supply service option or third-party supplier service option before becoming eligible to switch out of the chosen service. See, Current Rate IS Tariff.

Southern previously proposed to implement a minimum commitment period of five years in the proceedings in Docket No. 05-03-17PH02.In the Rate Design Decision, the Department denied the Company's proposal but stated that it would investigate the issue more thoroughly in future rate applications. The Company once again considered a term commitment of five years but deemed it to be viewed negatively by Rate IS customers. The Company believes a three-year term strikes the necessary balance between customer commitment/acceptance and capacity planning. Response to Interrogatory GA-406.

Southern asserts that the proposed minimum commitment period is not discriminatory ratemaking. Each tariff is in essence a contractual arrangement and treats every customer in that rate class the same. The interruptible class of customers is unique in terms of the service pricing and quality of service. It is not discriminatory to have different requirements for different tariffs as long as all customers subject to the particular tariff are treated the same. Southern Brief, p. 140.

Santa Buckley requested that the Department reject the Company's proposal to impose a discriminatory rate switching policy onto interruptible customers. Brief, p. 2. Further, Santa Buckley stated that VOS pricing ought to be reexamined. Santa Buckley PFT, p. 9. If the Department were to implement a cap on interruptible transportation rates, then the concerns of the Company regarding frequency of price-induced rate switching would disappear. Santa Buckley PFT, p. 6. Further, since December 2007, customers have been paying a premium over comparable firm rates for a lower quality of service. Santa Buckley believes that the Department should require that the interruptible tariff be modified to include language that puts a ceiling for the rate set at the lowest potential charge for the comparable firm service rate. With this change, the Company will not have to worry about temporary price-induced switches to firm service and the customers will not have to pay more for a lower quality service. Brief, pp. 5 and 6.

Southern believes setting limits on Rate IS pricing, as suggested by Santa Buckley, would throw the Department's long standing goal of interruptible margin maximization out the window and is not in the best interest of firm ratepayers. Southern Brief, pp. 140 and 141. The Company experienced a significant increase in demand in recent years from a variety of sources, including but not limited to electric generation and customer conversions. To the extent that any capacity becomes available in the market, the Company will take advantage of these situations anyway, as the region is fully subscribed. The Company does this not only to meet projected normal growth demand but also to have the ability to serve unexpected demand from a variety of sources as well. See, Southern Brief, p. 139; Tr. 3/25/09, 2290-2292.

The Department finds that the recent short term, extraordinary spread in pricing does not result in the need to increase the service commitment period for Rate IS customers at this time. Nor does it result in the need to reexamine the long standing VOS pricing principles the Department reaffirmed in the Cost Allocation Decision. The Department has long and firmly held policy that encourages the maximization of interruptible activity as it makes efficient use of secondary capacity. Further, the margins offset the costly infrastructure designed to meet the demand of firm customers. Requiring these customers to stay on a firm rate for a longer period will dimin-

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ish achievable margin levels and result in less available capacity to serve normal firm growth. This may result in the need for the Company to acquire incremental capacity that may otherwise have been freed up if the customer switched back to interruptible service. In the current economic environment, customers should be afforded a reasonable opportunity to seek a lower rate to the extent possible. The Department presumes that interruptible customers have made an investment in having dual fuel capability for the very purpose of retaining flexibility in use as well as to have negotiating power.

At this time, the Department finds there is no significant threat of stranded costs specifically related to the recent interruptible switching activity. The Department will continue to monitor the situation and potential for short-term cost shifting related to temporary price induced switches by interruptible customers. In the meanwhile, the Department expects that the Company will continue to use its authority under the Rate IS tariff to protect the integrity of its gas supply and avoid imprudently acquiring new supply sources for the purpose of satisfying short-term demand.

2. Definitions Section

The Department explored the feasibility of adding a general definitions section to Southern's tariffs. Current tariffs define some terms, which may be repeated several times throughout. Other terms, such as the various charges, are not defined. The Department believes and the Company agrees that it may be more administratively efficient to present these terms in a general definitions section of the tariffs. However, the Company cautioned that certain terms are tariff-specific, such as those in marketer-based tariffs, and therefore should remain within the specific tariff. The Company provided four terms that could be moved into a general definitions section. Late Filed Exhibit No. 56. The Company believes that it could be useful to have an expanded definitions section that would include general industry terms and definitions along with definitions of charges. Southern suggests incorporating the definitions section after the Table of Contents. Tr. 5/20/09, pp. 2436 and 2437.

It is administratively inefficient to create a definitions section just for a handful of terms solely for the purpose of eliminating redundancy in the tariffs. However, the Department believes that a more all-encompassing definitions section may be useful to customers. The Department envisions a definitions section that defines: 1) all customer charges; 2) relevant Company terms; and 3) relevant industry terms. This definitions section will help provide customers with a better understanding of their charges through a centralized location of various terms. While the definitions section will be all-encompassing, it likely would not eliminate redundancy completely within the tariffs. Certain definitions may also be restated, verbatim, within specific tariffs as necessary. On that basis, the Company will include a proposed definitions section in its tariffs.

3. Rate LGS Minimum Annual Consumption

C&I customers are assigned to specific rate classes based on their individual annual or reasonably anticipated annual consumption on a normalized basis. Pending the outcome of an annual review of normalized annual consumption, C&I customers may be reassigned to another rate class. Currently, customers whose annual consumption is less than 5,000 ccf are assigned to Rate SGS. Customers with annual consumption of 5,000 ccf to 19,999 ccf are assigned to Rate GS. Customer with annual consumption of 20,000 ccf or greater are assigned to Rate LGS. The Department explored the feasibility of raising the minimum annual consumption level for Rate LGS to 30,000 ccf. This would also raise the annual maximum allowable consumption level for Rate GS to 29,999 ccf.

Approximately 900 customers are currently receiving service under Rate LGS. Response to Interrogatory GA-254. Raising the minimum annual consumption level to 30,000 ccf would cause 312 Rate LGS customers to be reassigned to Rate GS, which represents 7,058,098 ccf of sales annually. Late Filed Exhibit No. 55. This change would result in load profiles with a higher average UPC for both Rates GS and LGS. Annual consumption level of 30,000 would also reduce the number of customers on the cusp of Rates GS and LGS, thus redu-

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cing the number of rate reassignments each year. Response to Interrogatory GA-254. The COSS and rate design revenue proof exhibits submitted using the Department Requested sales forecast reflect the necessary modifications to Rates GS and LGS annual consumption level requirements based on 30,000 ccf. Response to Interrogatory GA-2, Supplement No. 2, Attachment 3.

Southern does not endorse this change at this time for two reasons. First, the recent change that assigns C&I customers to rate classes based on annual consumption resulted in significant migrations from Rates SGS and GS to Rate LGS. Approximately 130 of those customers would again be affected, or "snapped back" by another rate migration in less than one year. Response to Interrogatory GA-2, Supplement No. 2, p. 2; Tr. 5/20/09, pp. 2441 and 2442. Second, the Company did not perform an analysis to show the rate impact of this migration on individual customers. Response to Interrogatory GA-2, Supplement No. 2, p. 2. Philosophically, the Company does not have a problem with changing the consumption level requirements for Rates GS and LGS. It is just the timing of this change that is of concern. Tr. 5/20/09, pp. 2445 and 2446.

The Department understands the Company's concern of not performing an analysis of the rate impact on individual customers migrating from Rate LGS into Rate GS, especially considering the sizable revenue requirement increase it proposed. However, seeing that Southern will experience an overall decrease to its revenue requirement, now is the time to change the breakpoint consumption level between Rates GS and LGS to 30,000 ccf. The overall revenue decrease will mitigate, if not totally eliminate any adverse bill impacts to the 312 customers migrating from the current Rate LGS to the new Rate GS. The Department does not accept the Company's argument that it would be somehow burdensome to the affected customers to be "snapped back" into Rate GS. The only concern regarding what rate class a customer is assigned would be the bill impact. Otherwise, it simply does not matter. Therefore, Southern is directed to revise its tariff language for Rates GS and LGS accordingly.

4. Availability Section of C&I Tariffs

The Department noted an error in Section 1, Availability of Southern's C&I tariffs regarding the basis of customer rate class assignment. Rates SGS, GS and LGS all state that these rates are available for C&I customers "with actual or reasonably anticipated" annual consumption. When in fact C&I customers are assigned to rates based on their normalized annual consumption. Therefore, the Department directs Southern to modify the applicable tariff language accordingly.

O. PIPELINE SAFETY

1. Cast Iron/Bare Steel Planned Replacement Program

The physical facilities of the Company include a large amount of underground plant, some of which is modern and state-of-the-art piping (e.g., coated, cathodically protected steel and plastic) and some of which is non-state-of-the-art (e.g., bare steel, cast iron). The Company has an ongoing program to evaluate its mains and services, particularly those that are non-state-of-the-art, and select for replacement or remediation those facilities that warrant the highest priorities. By having a program to replace facilities that are non-state-of-the-art, the Company can be proactive in preserving the safety of the public. While replacement of most of the facilities that are non-state-of-the-art is desirable, it is a long-term process. If the Department fails to address these issues today, while there are legacy systems that are not up to the current standards for new pipelines, the burden of this program will be carried forward. Should other facilities not currently known to be in need of attention come into question, the need may exceed the ability to address the important safety issues. By proceeding in as expeditious a manner as possible, the Department is promoting a safer system and avoiding a possible deluge of problems in the future.

To address the issue of pipe that is not up to the same standards as today's installations, the Company and the Department embarked on a program to address the years of inadequate replacement programs, which left a large

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amount of legacy pipelines. Since the early 1990s, the focus has been on trying to address these systems in a reasoned program with a view to eliminating them as soon as possible, while being cognizant of the financial costs to the ratepayers. The 2000 Decision on page 44, stated that "[t]he Department concludes that it is in the public interest for the Company to accelerate its replacement program."The 2005 Decision on page 15, stated that ". . . as the infrastructure has aged, the need for a more extensive integrity management programs has increased."

In the current case, the Company proposed to continue its existing Cast Iron/Bare Steel Planned Replacement Program (CI/BS Program) with a funding level of $8.013 million. Operations & Customer Relations PFT, pp. 5 and 6. The Company also requests to accelerate its CI/BS Program by an additional $1.5 million. In addition, funds are being added to the CI/BS Program that had been previously included under the Meter Relocation Program.

OCC stated that the 10-year average expenditure for cast iron and bare steel replacements is substantially more than the allowed figure. OCC requested expenditure amounts for all mains and services replaced, not just for the CI/BS Program. Pipe replacement programs include many components: planned replacement of pipe that is non-state-of-the-art; relocations to accommodate municipal relocation orders; and other activities. Response to Interrogatory OCC-171. OCC also stated that the Company's pipe replacement efforts do not appear to have affected the leak rates to a significant degree. Brief, p. 75.

Based on the aforementioned, the Department believes that the 10-year average expenditure for all mains and services replaced is artificially skewed upward and is not reflective of the actual expenditures for the CI/BS Program. The Department also believes that as non-state-of-the-art pipe ages, the leak rate tends to increase over time. If the leak rate is not decreasing, as Southern's is not decreasing, it reflects the need for further action to eliminate pipe of lesser integrity. This indicates that Southern is not replacing enough of the older pipe to lower the leak rate. The replacement rate is only keeping even with the amount of leakage. To improve leakage rates, it is necessary for Southern to replace more of the lower integrity pipe.

The Company's existing replacement program addresses ongoing O&M requirements. The Department believes that as the infrastructure has aged, the need for more extensive programs to address replacement of non-state-of-the art materials has increased. Furthermore, the US Department of Transportation Office of Pipeline Safety issued a Notice of Proposed Rulemaking creating new safety standards requiring Distribution Integrity Management Programs (DIMP). The regulation is expected to be finalized in 2009, and replacement of higher-risk pipe will figure prominently as a risk mitigation measure. Tr. 04/05/09, pp. 1024 and 1025. OCC stated that no formal studies have been performed by the Company on their plant to support the increase. While this is true, the Department has been actively involved in pipeline safety issues, both in hearings and as part of its on-going oversight responsibilities for pipeline safety. As part of its mission, the Gas Pipeline Safety Program of the Department regularly reviews the prioritization programs of the Connecticut gas companies. There is no need for a formal study to demonstrate what the Department has already determined. Pipe that is non-state-of-the-art represents a greater threat to public safety and needs to be replaced expeditiously. The Department concludes that it is in the public interest to approve the Company's request. Should the Company under-spend on its replacement program, it must include a program in its compliance filings designed to ensure that that the current year's capital expenditure carryovers are wholly used on meaningful replacement programs in the following year.

The Company requested to expand a capital program started in 2006 to increase the number of meters relocated to the outside of buildings and improve accessibility to shut off delinquent accounts at a total cost of $2.0 million per year. Operations & Customer Relations PFT, p. 8. While delinquent accounts are the main thrust of the Meter Relocation Program, there are other benefits to the general public as well as to gas customers in terms of pipeline safety and integrity. Tr. 04/15/2009,

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pp. 1032 and 1033. Some of the delinquent accounts are served by bare steel services. Tr. 04/15/2009, p. 1033. When the meter is moved outside to address the issue of delinquency, the non-state-of-the-art service line is replaced. This is because of the practical advantage of completing all of the work at one time. In certain cases, safety requirements include retesting of the service line and older service lines frequently cannot pass the required testing. The betterment achieved by replacing the service line has traditionally been charged to the Meter Relocation Program, rather than the CI/BS Program. However, the Department is directing the Company to discontinue its Meter Relocation Program as discussed in Section II.C.2.b. Meter Relocation Program. Twenty-five percent of the costs included in the Company's Meter Relocation Program are directly related to meter installation. The Company is directed to add the balance of $1.5 million of the discontinued Meter Relocation Program funds to the CI/BS Program. This accounting treatment will clarify the disposition of the funds as well as ensure that there is no net decrease in the allocation of funds used for the CI/BS Program.

2. Performance Measures

In the 2005 Decision, the Department ordered the Company to provide periodic performance filings. The Department remains concerned with the state of affairs involving risk-based pipeline safety programs, leak response, leak repairs and excavation damage. Therefore, the Department will continue to require monitoring of specific performance measures and filing of data on an on-going basis.

P. CUSTOMER SERVICE ISSUES

1. Southern Client Operating Procedures

a. Standard Bill Form and Termination Notice

In this proceeding, the Department reviewed Southern's proposed client operating procedures. Application, Schedule H-2. The Department found the Company's standard bill form and termination notice to be in conformance with applicable regulations.

The Company's customer rights notice states that there is a list of organizations willing to serve as a third party to receive customer shut-off notices; however, Southern admitted this list does not exist. In response to Department questioning, the Company proposed to amend future customer notices and to delete the obsolete reference to third party notice recipients. Tr. 4/8/09, pp. 35 and 36; Late Filed Exhibit No. 2. The Department reviewed the Company's submittal and approves it as proposed.

Southern sends termination notices in one of two ways depending on the time of year. The Company includes a copy of the customer rights notice with each termination notice. During the non-moratorium period (May 2-October 31), all termination notices are sent via first class mail. During the moratorium (November 1-May 1), Southern sends termination notices by certified mail to non-hardship customers with a delinquency above a certain dollar threshold. Termination notices are also sent to non-hardship customers whose balances fall below the threshold and to hardship customers as a reminder of their delinquent balance. The Company cannot take field action against hardship accounts during the moratorium or non-hardship accounts that have not been given a certified notice. Response to Interrogatory CSU-7.

In addition to sending notices, Southern makes outbound calls to delinquent customers. The automated calls leave a message stating they have a delinquency over 30 days and informs them of the balance they need to pay to maintain service. There is no other written documentation sent to the customer beside a termination notice to advise them of a delinquency. Once a customer is more than 60 days delinquent, the call center Customer Service Representatives (CSR) make live out bound calls to such customers. Tr. 4/8/09, pp. 38 and 39; Response to Interrogatory CSU-08. Southern does collect delinquent balances at a customer's door to avoid termination, which the Company testified frequently occurs with commercial accounts. Tr. 4/8/09, p. 40.

b. Tracking Customer Complaints

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Southern testified that it tracks complaints that are escalated to a supervisor. The Company submitted complaint statistics for calendar year 2007 and 2008, which reflect an increase in complaints. Late Filed Exhibit No. 1. Southern then set in motion a more formal procedure for reviewing its complaint statistics. The Call Center Manager and supervisor are now reviewing the complaint statistics on a weekly or sometimes daily basis to see where the Company can make improvements and avoid future complaints. In the area of operations, those complaints are reviewed on a monthly basis with the responsible individuals with a discussion on how improvements can be made. Tr. 4/8/09, pp. 31-35.

The Department finds that although Southern capably tracks those complaints that are escalated to a supervisor, the Company would benefit from reviewing and tracking all complaints. The Department urges Southern to consider developing a protocol to periodically review all complaints, whether resolved at the initial contact or not, and regardless of the complaint source. Then the Company could gain additional insight into its operations, as well as identify systematic issues sooner than would occur without such review and analysis.

c. Tracking Customer Complaints

Southern provides four to six weeks of training for CSRs. These CSRs are shadowed by veteran CSRs to accelerate and reinforce learning. The new trainees are coached and closely monitored by call center supervisors once they begin handling calls. Training is also done periodically on relevant topics such as reviews of hardship and energy assistance before the winter. Response to Interrogatory CSU-21. The Company testified that its CSRs were trained with regard to the Conn. Gen. Stat. § 16-259a(d) [FN6] when making payment arrangements. In addition to the training CSRs receive, a payment arrangement that comports with the statute is automatically generated. Tr. 4/8/09, pp. 47 and 48.

> FN6. Conn. Gen. Stat. § 16-259a(d) states: "Any company, electric supplier or certified telecommunications provider that holds a customer financially liable under subsection (a, (b), or (c) of this section shall establish a payment plan which prorates all arrearages for service the customer owes over a period of time that is no shorter than the period for which the customer is being held financially liable by such company, electric supplier, or certified telecommunications provider. The payment plan shall provide that no payment charged to a customer under such a plan shall exceed fifty percent of the average amount that the company charged such customer for each billing period over the previous twelve-month period for services received during that period."

The Department approves of Southern's CSR training and its application of Conn. Gen. Stat. § 16-259a(d).

d. Service Quality Measures

Southern plans to modify one of the benchmarks for its existing Service Quality Measures (SQMs). Southern previously established a benchmark of 35 seconds annually for the Average Speed of Answer (ASA) as a performance indicator. Company letter dated March 10, 2006 in Docket No. 05-03-17PH01.Southern proposed to revise its benchmark to 45 seconds annually. The Company has had difficulty in maintaining the 35-second benchmark due to the change in dynamics of calls to its Call Center. There are three factors that altered the number and duration of calls into Southern's Call Center: the volatility of natural gas prices; Southern has become more aggressive in its field and office credit and collection activities to reduce uncollectibles; and Southern has had difficulty in maintaining permanent staffing levels in its call center. PFT, Reis, Dobos, Malone, and McNally, pp. 18-22.

To date, the Department has not set specific ASA benchmarks for gas distributor utilities, and there are no specific standards set in state law or regulations for such benchmarks. The Department believes that the number and duration of calls into Southern's Call Center could be affected by the volatility of the natural gas prices and the Company's more aggressive credit and collection activities. In addition, the Department found

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that many utility customers are having increasing difficulty in paying their utility bills. This is because of the state of the economy, which has contributed to the change in the dynamics and length of calls. The Department has no objection to Southern's proposed change from 35 to 45 seconds for its ASA. The Department's Consumer Service Unit (CSU) will monitor Southern's performance of its SQMs (including hold times, abandoned call rates, and target staffing objectives) by requiring reports from the Company to identify deficiencies and needed improvements.

e. Estimates

Southern utilizes the Itron automated meter reading system to read meters on a monthly basis. If the Company is unable to obtain an actual read, the system will generate an estimated bill based on the customer's past consumption. A bill message is generated if a customer has been estimated more than one month. If a manual estimate has to be performed, it is based on degree days, base load, heating factor and the PGA that is appropriate for that month to calculate the bill. Application, Schedule H-2.0, p. 13.

The Department finds that Southern's estimate policy comports with Conn. Agencies Regs. § 16-3-102.

f. Deposits

Southern may require any customer to pay a deposit. Residential customers would be required to pay one quarter of an annual bill and C&I customers an amount that does not exceed the estimated maximum bill for 90 days. Deposits with interest are refunded to residential and C&I customers who have made 11 out of 12 and 17 out of 18 payments, respectively, on time. The customer is sent a letter advising that a refund will be applied to their account the month after the anniversary date of deposit receipt. A customer may also obtain a check reimbursement for their deposit by contacting the Company. Application, Schedule H-2.0, pp. 16-18.

In 2007, the Company implemented a new policy whereby a non-hardship residential customer would be required to give a deposit if they were shut-off for non-payment. Prior to this policy, residential customers were not required to do so. Southern found this to be an effective way to assist in reducing account receivables. Tr. 4/8/09, pp. 41 and 42.

The Department reviewed Southern's deposit policies for residential and C&I customers, and finds that they conform to Conn. Agencies Regs. § 16-3-200 and § 16-11-32a.

g. Residential Shut-off Policy/Soft-Close

Southern employs a soft-close policy, which means a residential customer's account is closed in the system but not physically shut-off at the time a customer is vacating the premises. The soft-close is applied under specific circumstances. [FN7]The final billing date is determined by the move-out date that is given to the Company by the customer. A customer vacating their premises will receive a prorated bill based on billing degree days and the base use factor. Southern checks the accounts that are coded as closed on a weekly basis to verify that no gas is being used. If the account remains inactive after 120 days or after 75 ccf of gas is consumed, the hard close process begins. Tr. 4/8/09, pp. 43 and 44; Response to Interrogatory CSU-20. Pursuant to Order No. 9 in the 2005 Decision, Southern provided a presentation to the Department's Consumer Service Unit explaining the soft-close policy.

FN7. The circumstances are:
- Residential accounts only
- Residence will be re-occupied within 12 months
- Not moving appliances
- Not demanding a meter be locked
- Meter has an ERT installed
- Consistent history of Itron reads

h. Payment Locations

The Company submitted a list of diverse Company operated and contracted locations where a customer can make a payment for no fee. The list provided the site, address and hours of the payment centers. A customer

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can obtain this information on the Company's website and it is also published in customer notices. Response to Interrogatory CSU-27, Supplement; Tr. 4/8/09, pp. 58 and 59. However, the hours of operation for the payment locations are not posted on Southern's website. The Department will direct Southern to add the hours of operation to the website list.

i. Payment Service Transaction Fees

Southern offers a bill payment service through a vendor (Kubra) which allows a customer to make an immediate payment over the telephone via a check or credit card. For each transaction, Kubra charges a fee to Southern as does the bank that is processing the payments. Reis, Dobos, Malone, and McNally PFT, p. 23. The Department believes that this is a beneficial service to provide customers with an immediate option for payment.

j. Customer Survey Results

Southern conducted a Customer Satisfaction Survey in 2008. In the survey, the Company had an overall positive customer satisfaction index of 89.5%. This percent was derived by averaging the positive characteristic ratings of the Company, customer service personnel and field technicians. The Company was rated in 13 different areas and the respondents gave an overall average positive rating of 85.5%. Response to Interrogatory CSU-03, Attachment p. 6.

The Department notes that a customer survey gives the Company insight into its performance; however, it is only a snapshot of customer views. The Department believes that by reviewing all customer complaints and inquiries, Southern can work toward improving problem areas.

Q. ENERGY EFFICIENCY

The Company indicated that in response to the state's policies encouraging energy efficiency and as part of their integrated decoupling vision to proactively assist customers in energy conservation, Southern proposed to expand its portfolio of natural gas efficiency programs. Specifically, the Company plans to offer new or expanded energy efficiency programs, communication, outreach and education and training programs. Dobos and Spellman PFT, pp. 4 and 5. Currently, Southern has an approved budget of $2.902 million for its 2009 conservation plan (2009 Plan) approved in the Decision dated February 25, 2009 in Docket No. 08-10-02,DPUC Review of the Connecticut Gas Utilities Forecasts of Demand and Supply 2009-2013 and Joint Conservation Plans. The Company proposed to increase this spending level by approximately $98,000 to $3 million per year. Dobos and Spellman PFT, p. 16. Its proposal to strengthen and expand these programs is contingent upon two factors. Specifically, Department approval of rates sufficient to support the 2009 Plan and budget, as well as the rate design changes that would decouple the Company's distribution revenues from its volumes of natural gas sales. Dobos and Spellman PFT, 11.

In its proposal, the Company plans to address the supply-side and the demand-side of energy efficiency markets. For the supply-side, Southern would work with program allies to ensure that high efficiency equipment is available and promoted. The Company would work with the demand-side of the market to ensure that consumers are aware of the costs and benefits of energy efficiency measures and high efficiency natural gas equipment, and to increase the consumer demand for such equipment from suppliers. This use of expanded communication, outreach, education, and training programs would be a key component of the plan and logic model for each program. Southern proposes to use an array of marketing methods to ensure that customers have access to up-to-date and accurate information about costs, savings, performance, and reliability of energy efficiency measures and equipment. Dobos and Spellman PFT, pp. 5 and 6.

The Company acknowledged that market barriers exist that prevent or inhibit the purchase and installation of high efficiency equipment and building practices, such as inadequate supply of high efficiency equipment, lack of information for consumers and perceived problems for contractors. Dobos and Spellman PFT, p. 23.

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However, the Company did not indicate how its proactive approach to promoting conservation would address these market barriers. Further, the proposed education and outreach effort has not been approved by the Energy Conservation Management Board (ECMB), nor did the Company consult with the ECMB in its development. Depending on the determination made in the instant case, the proposal would then be vetted before the ECMB. Response to Interrogatory OCC-141; Dobos and Spellman PFT, p. 25. A breakdown of the proposed costs, total resource cost (TRC) test benefit cost ratios and projected savings are provided in the following table:

Program Name	Proposed Budget	Estimated TRC Benefit/ Cost Ratio	Projected Annual ccf Savings
RESIDENTIAL SECTOR			
Low Income Weatherization	$700,000	2.10	124,690
Low Income Audits	15,000	N/A	N/A
Home Energy Solutions	778,219	3.15	108,278
Water Heating	121,000	1.04	15,198
Energy Star Homes	300,000	2.15	81,600
Total Residential Sector	$1,914,219	2.31	329,766
COMMERCIAL SECTOR			
Energy Conscious Blueprint	$174,509	1.42	103,147
Process Retrofit Pilot	347,393	1.54	205,334
Energy Opportunities	361,197	1.54	213,493
O&M	82,146	1.18	48,554
Total Commercial Sector	$965,245	N/A	570,527
OTHER			
CHIF Loan Fund	$30,000	N/A	N/A
Planning	50,536	N/A	N/A
Evaluation	31,000	N/A	N/A
ECMB	9,000	N/A	N/A
Total Other	$120,536	N/A	N/A
TOTAL SOUTHERN BUDGET	$3,000,000	1.97	900,293

Dobos and Spellman PFT, pp. 29 and 31.

The Company indicated that in the event there are no excess GRT funds available, funding and recovery of all costs of the existing and proposed programs would pass through the existing CAM. Dobos and Spellman PFT, p. 26.

OCC believes that this rate case is not the vehicle for resolving a small difference between Southern's pro-

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posed expenditure of $3 million and its approved conservation budget for 2009 of $2.902. Rather, any desire by the Company to increase its efficiency expenditures would occur through the ECMB in a separate Department proceeding. OCC is willing to work with the LDCs and the Department as necessary to avoid duplicative expenditures between the biennial demand and supply dockets and rate case dockets as to energy efficiency plans and budgets. Brief, pp. 139 and 140.

The Department believes that the existing 2009 Plan program objectives are adequate at this time to meet customer needs and the state's overall goals related to natural gas conservation. Further, not all of Southern's conservation programs are fully subscribed at this time. Energy prices in general as well as an overall public policy shift in promoting conservation and/or alternative energy are major factors influencing both demand for Company sponsored programs and customer-driven conservation efforts. Because of heightened consumer awareness, the Department finds that the Company's proposed expansion in outreach efforts unnecessary at this time. The Company can propose additional outreach efforts as part of its upcoming annual conservation budget filing. The Company will be directed to record customer information for referral to its Conservation and Load Management Department on all customer inquiries about conservation programs via phone or letter.

The Department agrees with OCC that energy efficiency proposals are best suited for the annual review of the LDCs' joint conservation plans, not in a general rate case. The Department notes that conservation related expenditures have been eliminated from the Company's O&M expenses in the instant case. They will be collected through the CAM mechanism in the event that other sources of non-ratepayer funding are unavailable. To avoid any further unnecessary expenses for ratepayers, energy efficiency proposals only should be proposed in the annual joint conservation plan. It is also important for the Company to investigate alternative funding sources, rather than relying solely on ratepayer funding. By letter dated May 18, 2009, Southern was directed to evaluate the availability of federal funding and apply for any available funding for conservation measures. If awarded federal funding, the Company was directed to use this source for incrementally increasing customer incentives for conservation. As is current practice, should demand for Southern's conservation programs cause it to potentially exceed its available budget and no alternative funding is available, it shall seek Department approval prior to making additional ratepayer funding available.

R. COST OF CAPITAL

1. Introduction

In Federal Power Commission v. Hope Natural Gas Company, 320 US 591 (1944) (Hope Decision), the Court established criteria to determine cost of capital allowances. In its Decision, the Court determined that companies need to be allowed to earn a level of revenues sufficient to enable them to operate successfully, maintain their financial integrity and to attract capital and compensate their investors for their risk. By Connecticut law, utilities are entitled to a level of revenues that will allow them ". . . to cover their operating and capital costs, to attract needed capital and to maintain their financial integrity, and yet provide appropriate protection for the relevant public interest both existing and foreseeable."Conn. Gen. Stat. §16-19e(a)(4).

To determine a rate of return on rate base that is appropriate for Southern's overall cost of capital, the Department first identifies the components of the Company's capital structure. The cost of each capital component is then estimated and weighted according to its proportion of total capitalization. These weighted costs are summed to determine the Company's overall cost of capital, which becomes the allowed rate of return on rate base (ROR).

2. Capital Structure

The Company proposed that the following pro forma capital structure that was developed by starting with the test year capitalization levels and adjusting these to the midpoint of the rate year, December 31, 2009, by ad-

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justing for future anticipated financings, dividends, and retained earnings. RRP PFT, p. 57. The capitalization ratios were based on debt and equity amounts reported on Southern's books starting with test year levels.

Class of Capital	Amount	% of Total	Cost	Weighted Cost
Long-Term Debt	$196,135,758	42.39%	7.20%	3.05%
Common Equity	$266,596,924	57.61%	12.20%	7.03%
Total Capitalization	$462,732,682	100.00%		10.08%

Schedule D-1.0.

In its Application, Southern did not include short-term debt in its capital structure. Southern's expert witness Dr. Makholm believes that the Company's use of short-term debt is highly seasonal in nature having short-term balances only a few months of the year. He concluded that short-term debt is not a consistent source of funding for long-term assets. Dr. Makholm asserts that the extraordinary capital market conditions in today's markets warrants an examination of whether short-term debt should be included in Southern's capital structure. In the early 1980s, utilities first proposed to include short-term debt in capital structures to preserve their financial integrity during times of extraordinary capital market conditions. It is now important to exclude short-term debt from a utilities' capital structure due to the current extraordinary events, which are nearly opposite of the events in the early 1980s. He notes that the current spreads between long-term and short-term debt are far above average compared to the early eighties where the spread was far below average or even negative. Makholm PFT, pp. 54 and 55.

Dr. Makholm believes that short-term debt is generally not included in a utility's capital structure for ratemaking purposes since only permanent sources of capital should be in the capital structure. Makholm PFT, p. 55. It is the practice of most state commissions regulating gas distributors in the United States to exclude short-term debt for ratemaking purposes. Makholm PFT, p. 18.

Dr. Makholm stated that if the Department were to decide that short-term debt should be included in the capital structure it would be necessary to exclude short-term debt related to construction work in progress (CWIP). He points out that the allowance for funds used during construction (AFUDC) comes first from short-term debt and then, once that is exhausted, from the overall cost of capital. It would be necessary to exclude AFUDC related short-term debt from the capital structure for ratemaking purposes given that CWIP is generally not included in rate base until the plant is deemed used and useful. Dr. Makholm also cautions not to avoid the effective disallowance of working capital from recovery in the revenue requirement by partially offsetting the working capital rate base by including short-term debt in the capital structure. Makholm PFT, p. 56.

OCC's witness, Dr. J. Randall Woolridge, asserts that Southern's projected capital structure is not appropriate for ratemaking purposes in the instant case. Dr. Woolridge stated that Southern's recommended capital structure consists of a common equity ratio of 57.61%. This is significantly higher than the common equity ratios of Southern's parent, Energy East, gas distribution companies, and Southern's cost of capital witness Dr. Makholm's comparison group of companies. Woolridge PFT, p. 17.

Dr. Woolridge provides the capital structure ratios for Energy East over the past five years, which do not include short-term debt. The average common equity ratio over these five years is 39.8%. Dr. Woolridge asserts that Energy East's capitalization is significant for two reasons. The first reason is that this is the capitalization that Southern ultimately employs to attract debt and

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equity capital in the market place. Secondly, as indicated in credit reports, Southern's credit ratings are strictly a function of the overall credit profile of Energy East and not Southern alone. The costs of debt and equity capital for Southern are reflective of the capitalization of Energy East and not Southern. Woolridge PFT, pp. 17 and 18.

In addition, Dr. Woolridge provided an analysis of the equity in his gas distribution company proxy group concluding that the average common equity is at 49.9%. The appropriate common equity ratio for gas distribution companies including short-term debt is approximately 50%. Dr. Woolridge notes that Dr. Makholm's comparison group's common equity ratio is at 47%. Woolridge PFT, p. 18. Dr. Woolridge takes exception to the exclusion of short-term debt in Southern's capital structure since 7.03% of Southern's capital is projected to include short-term debt. He notes that Southern regularly employs short-term debt in its capitalization. Woolridge PFT, p. 18; Response to Interrogatory OCC-115. Dr. Woolridge concludes that Southern's requested capital structure is not appropriate because it is not reflective of the capital structures of Southern's parent Energy East, gas distribution companies, Dr. Makholm's comparison group, and it does not include short-term debt. Woolridge PFT, pp. 18 and 19. The capitalization ratios and cost rates recommended by Dr. Woolridge are shown below.

Capital	Capitalization Ratios
Short-term Debt	7.57%
Long-Term Debt	42.43%
Common Equity	50.00%
Total Capital	100.00%

Woolridge PFT, Exhibit JRW-5, Panel F.

To construct the above imputed capital structure, Dr. Woolridge used a 50.0% common equity ratio. He then increased the allocation proportionally of short-term debt and long-term debt to match a 50% allocation for those two sources of capital such that they represent 50.0% of capital along with a 50.0% common equity ratio. Woolridge PFT, p. 19.

Southern is a party along with other Energy East affiliates to a Joint Revolving Credit Facility (Joint Facility). Southern has a maximum credit capacity of $100 million under the Joint Facility. Southern's short-term debt averaged $22,567,738 during calendar year 2008. Response to Interrogatory OCC-115. Southern regularly uses its Joint Facility for the purchase of gas supply, typically during the winter heating season months. Although it does not always carry a balance of short-term debt, the evidence suggests that short-term debt is relied upon frequently. Response to Interrogatory OCC-115.

The Department's analysis indicates that while not a majority of local gas distribution companies include short-term debt in their capital structure, a significant number do. The Department concludes that including short-term debt in the capital structure is not as unusual as Southern has portrayed it.

The Department takes note of other rate case Decisions in which short-term debt was included in the capital structure such as the Decision dated May 25, 2000 in Docket No. 99-09-03,Application of Connecticut Natural Gas Corporation for a Rate Increase and the Decision dated October 13, 1995, in Docket No. 95-02-07PH01,Application of the Connecticut Natural Gas Corporation for a Rate Increase. In the latter Decision on page 65, the Department stated:
The Department has in the past and continues to incorporate short-term debt in the capital structure, although by definition it is not permanent financing. For purposes of ratemaking, however, CNG's short-term debt should be included in the capital structure since it is a continuous source of yearly funding.

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In the instant case, the Department finds that short-term debt is a permanent source of capital for Southern in its capital structure. Due to Southern's reliance on short-term debt, it should be included in its capital structure for ratemaking purposes. The Department also finds that since Southern's short-term debt is used to fund gas supply purchases then an adjustment for AFUDC is not necessary. The Department uses a $22,500,000 projected balance for short-term debt, which is based on the 2008 average monthly balances.

a. Adjustment to Common Equity

Southern overstated the test year's common stock equity dollar amount by not reducing it by $13,517,027, the accumulated amortization of plant acquisition adjustment, or accumulated amortization of goodwill. The Company reduced plant goodwill by the accumulated amortization accrued to date prior to its adoption of the Statement of Financial Accounting Standard (SFAS) No. 142, which prohibits further amortization of acquisition related goodwill. The Company claimed that the recorded amortization expense was not included in base rates and not recovered from ratepayers. Tr. 4/08/09, pp. 128 and 129; Responses to Interrogatories GA-28 and GA-475 Attachment, p. 8; Schedule D-5.0. For the test year, Southern reported total common stock equity of $485,289,601. The amount includes $245,936,667 of additional paid-in capital or acquisition adjustment from the Energy East merger with Connecticut Energy Corporation (CEC). Response to Interrogatory GA-475 Attachment, pp. 10 and 11. The Company reported $13,517,027 as the accumulated amortization of the acquisition adjustment. Id, p. 8. The Company net common stock equity for the test year is the gross common stock equity less the accumulated provision for amortization of acquisition adjustment or $471,772,574 ($485,289,601 - $13,517,027).

The Department believes that by not reducing common stock equity by the accumulated amortization of goodwill, the Company is overstating the equity portion of its capital structure and indirectly overstating both its ROE and ROR. Both the ROE and ROR eventually determines the Company's allowed revenue requirement. The Department adjusted Southern's capital structure for the amortization of goodwill. In the Decision dated December 16, 1999 in Docket No. 99-07-20,Joint Application of Energy East Corporation and Connecticut Energy Corporation for Approval of a Change of Control (CEC Merger Decision), the Department approved the merger of Energy East with CEC, the parent of Southern. In that merger, Energy East gained control of Southern. Under that transaction, goodwill was defined as the excess of the purchased cost over fair value of the net assets. The Department accepted the applicants' intention that goodwill related expense or investment will not be used for the purpose of determining the rates charged to ratepayers. CEC Merger Decision, p. 17. Absent this merger, the Company's common stock equity for the test year is $239,352,934 ($485,289,601 - $245,936,667).

The Company acknowledges that absent the CEC merger, Southern's common stock equity for the test year would be $239,352,934, which is the total test year's common stock equity of $485,289,601 less the total merger related paid-in capital of $245,936,667. See, Tr. 05/07/09, p. 2355. The Department's calculation of Southern's common stock equity dollar amount for the rate year is shown below:

Calculation of Rate Year's Common Stock Equity

Line	Item	Amount ($)
1	Test Year Amount	485,289,601
2	Less Amortization of Plant Acquisition Adjustment	(13,517,027)
3	Net Test Year Common Equity (Line	471,772,574

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	1+Line 2)	
4		
5	Plant Acquisition Adjustment - Goodwill	(245,936,667)
6	Less Amortization of Plant Acquisition Adjustment	13,517,027
7	Net Plant Acquisition Adjustment (Line 5+Line 4)	(232,419,640)
8		
9	Less Accumulated Other Comprehensive Income	(1,023,963)
10	Pro- forma Retained Earnings	13,324,000
11		
12	Rate Year Common Stock Equity (Lines 3+7+9+10)	251,652,971

Response to Interrogatory GA-2 Corrected, Attachment 2, p. 51; Late Filed Exhibit No. 7.

Based on the above calculation, the Department determines that the Company's common stock equity for the rate year is $251,652,971, which is $13,517,027 less than the Company's proposed amount of $265,169,998. See, Response to Interrogatory GA-2 Corrected, Attachment 2, p. 51.

In its Written Exceptions, the Company incorrectly noted that the issues involving the $13,517,027 accumulated provision for the Utility Plant Acquisition Adjustment was not raised at any time during the proceeding until it was raised in the Draft Decision. The Company also stated that the Department ignored the "extensive exchange...in which the Company's witness clarified, repeatedly, that, absent the merger between the Company and Energy East, SCG's [sic: Southern's] test year common equity would be adjusted by lines 1 and 2 on Schedule D-5.0." Written Exceptions, pp. 29 and 31.

The Department disagrees with the Company that the issue was not raised before the issuance of the Draft Decision. In fact, this issue was raised in several interrogatories stated therein and on the first day of hearing. See, Tr. 04/08/09, pp. 127-132 and Response to Interrogatory GA-28. Based on the journal entries provided by the Company to eliminate the effects of both the goodwill recorded to paid-in-capital and goodwill amortizations, the Department determines that the Company must have made initial journal entries to record both transactions as follows:

a. The journal entry under the Uniform System of Accounts to initially record the effect of the portion of goodwill recorded to paid-in-capital of $245,936,667 is as follows:

	Debit	Credit
Account 114 - Utility Plant Acquisition Adjustment	$245,936,667	
Account 211 - Miscellaneous Paid-in Capital		$245,936,667

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b. The journal entry under the Uniform System of Accounts to initially record the effect of goodwill amortizations of $13,517,027 is as follows:

	Debit	Credit
Account 406 - Amortization of Utility Plant Acquisition Adjustments	$13,517,027	
Account 115 - Accumulated Provision for Amortization of Utility Plant Acquisition Adjustments		$13,517,027

Based on the Department's determination of the initial entries, the Company's first elimination journal entries removed the effect of the acquisition adjustment from Southern's common stock equity. The Company's second elimination journal entries to Accounts 115 and 406 removed the effect of recording amortization expenses from Southern's income statement. However, at the operating Company level, Southern should not be making the third Company's elimination entries to the Income Statement Summary and Account 216. The elimination entries to Accounts 115 and 406 should have removed the effect of the amortization expenses from Southern's income statement. Any journal or elimination entries done in a consolidated financial report should not have any impact on the calculation of the Company's regulatory common stock equity amount. All this said, Conn. Gen. Stat. § 16-22 clearly lays the burden of proof on the Company. It is odd that the Company would suggest that the Department must point out the Company areas of its own Application before the Department can address those areas in its Decision.

As discussed below, the Department has determined that the Company's capital structure should reflect no more than 52% common equity. As such, the Company's actual amount of common equity, whether it is $265,169,998 or $251,652,971, has only a minor impact on the revenue requirements ultimately allowed.

b. Summary of Capital Structure

The Company is requesting approval of a pro forma capital structure of 42.39% long term debt (LTD) and 57.61% Common Equity. Schedule D-1.0. The Company reports no preferred stock and makes no inclusion in its proposed capital structure for short term debt. It is a generally accepted premise that equity costs more than debt, and that the interests of shareholders, rather than ratepayers, are served as the percentage of equity in the capitalization mix of a regulated utility increases.

The Company presented a proxy group of nine firms and used The Value Line Investment Survey to approximate the average equity ratio of the proxy group at 54.6%. Makholm PFT Exhibit JDM-5; Response to Interrogatory GA-106.

Dr. Woolridge, used data from the AUS Utility Reports to estimate the average equity ratio of Southern's proxy group members at 47%. Woolridge PFT, Exhibit JRW-13, Panel A. Dr. Woolridge also reported the equity ratio of Southern's parent company, Energy East, as 39.8% and stated that this ratio was what Southern ultimately uses to attract capital in the marketplace. Woolridge PFT p. 19. Dr. Woolridge presented an alternate gas distribution proxy group, and reported its average common equity ratio as 49.9%. Woolridge PFT, p. 20.

The Department finds Southern's proposed capital structure to be equity rich when compared to the proxy groups and other regulated utilities, as it consists of almost 58% equity. This capital ratio does not balance the needs of shareholders and ratepayers and is at odds with the financial risk incorporated in the allowed cost of

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equity since this cost is based on the proxy group. See, Section II.R.5. Cost of Equity The Department will limit the equity ratio to 52% for ratemaking purposes. The Department approves the following capital structure for Southern regulated gas operations only:

Class of Capital	Percent of total
Debt	48.00%
Common Equity	52.00%
Total Capitalization	100.00%

3. Cost of Short-Term Debt

As mentioned previously, the Joint Facility is available to Southern for its short-term borrowing needs and is a syndicated facility with 17 banks participating in it. The syndicated short-term debt market is a large market in which pricing and terms are comparatively transparent. Under this syndicated facility arrangement, a lead agent bank is responsible for negotiating pricing and terms and selling the loan into the market. A lead agent bank is chosen after meeting with several potential lead agent banks soliciting comments on current market conditions and indicative rates. After these meetings, a lead agent bank is chosen on the basis of proposed pricing, terms, and syndication track record. When the joint revolver was originally arranged in 2005 and subsequently amended in both 2006 and 2007, Wachovia was the lead syndication agent. The Joint Facility is effective until June 2012 and pricing is locked in until that time. It bears an interest rate based on the London Interbank Offering Rate (Libor) of 2.00% plus a spread of 0.19%. Up-front fees and expenses are amortized annually through June 2012. A facility fee of 6 basis points is paid in lieu of compensating balances. The credit line is $100 million. Response to Interrogatory OCC-115.

Southern was made a party to the Joint Facility in June 2005. To take advantage of favorable conditions in the short-term bank lending market, the Joint Facility was re-priced in May of 2007. Due to the actions taken in June 2005 and May 2007, Southern's facility fee was lowered from 2 basis points to 8 basis points. Southern's Libor borrowing margin was lowered to 27 basis points, a reduction of 29.25 basis points. RRP PFT, p. 59.

OCC proposed a cost of short-term debt of 1.75%. To obtain the proposed cost rate Woolridge used the current Libor of 1.25% and added 50 basis points for allocated fees and expenses. Woolridge PFT, p. 19.

Southern stated that Dr. Woolridge's proposed cost of short-term debt is too low given fluctuations in the Libor rate, which is now at current historic low levels. Southern asserts that a cost for short-term debt that will reflect Libor in the rate year should be the midpoint between Dr. Woolridge's 1.25% and the 4.7% experienced in 2008. This is 2.98% plus allocated fees and expenses of .48% for a total short-term debt cost rate of 3.46%. Brief, p. 45.

The Department believes that Dr. Woolridge's short-term debt cost of 1.75% is too low because it is not reflecting the cost of the short-term debt based on the Company's actual cost to date. The Department finds that Southern's proposed cost of short-term debt of 2.48% is reasonable and approves it.

4. Cost of Long-Term Debt

Southern requested a cost of long-term debt of 7.19%. Response to Interrogatory OCC-157; Revised Schedule D-3.0. Southern stated that it has been diligent in its efforts to lower its cost of long-term debt citing its January 2005 filing for approval to issue up to $110 million of unsecured medium-term notes (MTNs) in the Decision dated January 26, 2004 in Docket No. 05-01-01,Application of The Southern Connecticut Gas Company for Approval of Issuance of Its Secured Medi-

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um-Term Notes. In October 2005, Southern issued $45 million of 30-year MTN's carrying an average coupon of 5.775%, which is more than 200 basis points below the average coupon of the portfolio prior to the issuances. RRP PFT, pp. 58 and 59. OCC accepted this cost of long-term debt. Woolridge PFT, p. 20. The Department finds Southern's efforts to lower its cost of long-term debt admirable. The Department approves Southern's embedded cost of long-term debt of 7.19% for the rate case.

In Written Exceptions, the Company argued that the 7.19% embedded long-term debt cost included merger related debt and that exclusion of this debt raised its long-term debt cost to 7.24%. Written Exceptions, p. 25. While the Department believes it appropriate to exclude the effects of the merger-related expenses, the approved capital structure has more debt and less equity in it than Southern's actual capital structure. As such, it is appropriate to assign some of Southern's equity to merger-related financing and some of the merger-related debt to Southern's approved capital structure. For this reason, the Department finds the 7.19% long-term debt rate appropriate.

5. Cost of Equity

a. Introduction

Dr. Makholm recommended 12.2% as an appropriate equity cost rate regardless of whether or not the Department approved a decoupling mechanism for Southern. He believes that decoupling has no effect on a utility's cost of equity. Makholm PFT, p. 45.

Dr. Woolridge proposed an equity cost rate in the range of 7.00% to 9.60% for Southern. He used an equity cost rate at the upper end of the range of 9.00% in recognition of the volatile capital market conditions. OCC's proposal includes a 25 basis point downward adjustment under the presumption that the Department adopts a decoupling rate mechanism. Woolridge PFT, p. 3.

b. Methodologies Used by Both Expert Witnesses

i. Discounted Cash Flow

The discounted cash flow (DCF) model assumes that an investor in the common stock of a company expects returns in the form of periodic dividend payments plus capital gains from the sale of the investment (higher dividend payments will cause an increase in stock price, other factors being equal). The model equates the market price of the investment to the present value of the investor's anticipated cash flows at the investor's required rate of return. The determination of the investor's required return is accomplished through an internal rate of return calculation, which is, in effect, the compounding of interest in reverse. For example, in a typical compound interest problem, the initial investment price and interest rate are given. The cash flows which are interest payments are calculated. With the DCF methodology, the investment price and the expected cash flows (dividends and capital gains) are "given." The investor rate of return or "interest rate" is solved with an internal rate of return calculation. The formula for the DCF is as follows:

$k = D_1/P_0 + g$

Where:

k = the investor's required return

D_1 = the next period's dividend

P_0 = the market price of common stock

g = the investor's expected growth rate

ii. Capital Asset Pricing Model

The capital asset pricing model (CAPM) is based on the theory that the relevant risk of any asset is its relative contribution to the total variability of the market portfolio held by all investors. That is to say, investors are able to invest in a variety of portfolios of different risks and made up of various combinations of assets including a risk free asset. This risk free asset has no chance of default and has a guaranteed real rate of return. Under these parameters, a rational investor would only invest in market portfolios yielding a return comparable to a similar risky combination of a perfectly diversified market portfolio and the risk free asset. In this situation, an investor would only need to be compensated for a company's nondiversifiable risk since any other risk could be eliminated in a properly balanced portfolio.

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The formula for the CAPM is as follows:
$K = R_f + B (R_m - R_f)$
where: K = required return on equity
R_f = return required on the risk free asset
R_m = return on the perfectly diversified portfolio
B = common equity beta risk measure or the nondiversifiable risk relative to the perfectly diversified portfolio

c. Summary of Dr. Makholm's Testimony

i. Overview

Dr. Makholm evaluated Southern's cost of equity and determined a fair rate of return on common equity for the Company to be 12.20%. This was based on applying the DCF methodology, CAPM, and as a check a yield plus growth (YPG) methodology. This fair rate of return lies within the broad range of 10.81% to 12.51% of Dr. Makholm's DCF, CAPM, and YPG results. The lower and upper bounds are based on his calculations for DCF and CAPM analyses of a comparable group of U.S. local gas distribution companies (LDCs) and combination gas and electric utilities that, in Dr. Makholm's opinion, reflect the business risk of Southern's regulated utility operations. His YPG method for the natural gas utility industry produced a cost of equity result of 12.27%. Dr. Makholm used this as a check of reasonableness on his 12.20% cost of equity recommendation. Makholm PFT, pp. 2-4. Dr. Makholm stated that the purpose of the recommended 12.20% cost of equity was that it would lead to an "A" bond rating for the Company. Tr. 4/20/09, p. 1774. Dr. Makholm further stated that the achievement of raising the Company's credit rating to "A" was a Company goal. Tr. 4/20/09, p. 1771. However, the Company has stated that its long term goals could be served by maintaining its current bond rating of BBB+. RRP PFT, p. 59.

ii. Selection of a Comparable Group

To determine Southern's cost of equity, Dr. Makholm used a comparable group of nine U.S. gas LDCs and combination gas and electric utilities that in his estimation are comparable to Southern's regulated utility operations. His reasons for using multiple firms to determine the fair rate of ROE, even if company specific data is available, are:
1. A group of companies produces a more reliable and objective estimate of the current cost of capital required by capital markets.
2. The computation of comparable group's fair rates of return gives substance to the Hope Decision's finding that a reference should be made to return on investments with corresponding risks.
3. A specific jurisdiction's regulatory process affects investor expectations regarding the company whose fair rate of return is being set. A potential problem that the use of a comparable group of companies from a number of states avoids.
Makholm PFT, pp. 28 and 29.

Dr. Makholm's first basic objective to determining a comparable group is to assemble a group of companies having publicly traded stock that are representative, on average, of the business risk faced by Southern's gas LDC delivery service operations. His second basic objective is to assemble a group of companies with stock price and dividend payment data that could be readily used in the DCF model. Makholm PFT, pp. 28 and 29.

Dr. Makholm finds that his first basic objective is met by using two characteristics that define business risk, which are type of business and size. Employing these characteristics, he used two criteria to exclude companies from his comparable group. The first criteria was to select those electric and combination electric and gas utility companies that derive at least 85% of operating revenues from regulated electricity and gas operations. He calculated 93.48% as the average proportion of total operating revenue from state regulated utility activity in 2007 for the comparable group. The second criterion was to restrict the comparable group of companies to those with a total capital of less than $10.0 billion. Southern's total capital is about $355 million. Dr. Makholm recognizes that the utilities in his comparable group have a higher total capital than Southern. His goal was to create a comparable group that is representative of the business risk faced by Southern. The average total capital for the group is approximately $2.624

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billion. Makholm PFT, pp. 29 and 30.

To satisfy his second basic objective to assemble a group of companies with stock price and dividend payment data that can be easily applied to the annual DCF model, Dr. Makholm established two additional criteria to form his comparable group. The first criteria was to restrict the comparable group to utilities where there was no data to suggest the utilities would not maintain its existing dividend. Dividend maintenance was essential to Dr. Makholm's analysis. The DCF model he employed assumes a constant long-term dividend growth rate. He reasoned it would be inappropriate to apply the DCF model to utilities where a dividend decrease is expected. In addition, he excluded utilities from his analysis that are publicly known targets of possible takeovers or are involved in mergers. Dr. Makholm reasoned that tender offers associated with takeovers generally affect stock prices in a temporary way unrelated to the overall cost of capital and as such should not be employed in a DCF analysis. Makholm PFT, p. 30.

The result of Dr. Makholm's applying his criteria to a universe of utilities is a group of nine U.S. gas LDCs and combination gas and electric companies that he believes are comparable to Southern's regulated utility operations. Dr. Makholm believes that his comparable group has a degree of risk that is comparable to Southern. Makholm PFT, p. 30. Dr. Makholm's nine member comparable group are Piedmont Natural Gas, Northwest Natural Gas, Southwest Gas, Nicor, Avista Corporation, Wisconsin Energy, MGE Energy, Alliant Energy, and NStar. Makholm PFT, Exhibit JDM-5.

iii. DCF Model

Dr. Makholm's DCF analysis used three data inputs of current stock prices P_0, the current annual dividends D_0, and estimated dividend growth rates g for each of the utilities in his comparable group. Stock prices were obtained from the *Yahoo! Finance* data base. He used a closing stock price on November 18, 2008, which was the last possible day given Southern's filing date in this docket. Dr. Makholm's practice is to use stock prices on the latest day consistent with the filing. He reasons that only the latest stock prices are consistent with up-to-date investor expectations. It is a widely held tenant of efficient markets that the informative value for investor expectations of yesterday stock prices is superseded by today's stock prices. Makholm PFT, p. 31.

Dr. Makholm took these stock prices, for his comparable group, and performed an ex-dividend date adjustment to remove the known affect that the next quarterly dividend payment has on the stock prices. He believes this ex-dividend adjustment is necessary since without it would make the stock price inconsistent with the DCF formula. The DCF formula assumes that the next quarterly dividend will be received one full period from the date the stock price is measured. Usually the next quarterly is closer than one full quarter from the day the stock price is measured. Due to this the stock price must be adjusted to avoid a downward bias in the calculated result. Makholm PFT, pp. 31 and 32.

Dr. Makholm defines the ex-dividend date as the date on which the right to the next dividend no longer accompanies the stock. Dividends are an important part of the return to utility shareholders and considering the relatively high payout ratios, the ex-dividend date is a significant determinant of the stock price. Utility stock prices drop by an amount approximately equal to the quarterly dividend on the ex-dividend date as is also observed in other stock prices. Dr. Makholm believes that failure to adjust the stock price taken at an arbitrary date to account for the ex-dividend date will bias the stock price upward by approximately the amount of the accrued portion of the quarterly dividend and as such the resulting DCF calculation will be pressured downward. Makholm PFT, p. 32.

The calculation Dr. Makholm used to make this ex-dividend adjustment is removing from the stock price the portion of the dividend that has already accrued. He made this adjustment to the P_0 term before performing the DCF calculations for his comparable company group. The actual mechanics of the calculation is that he subtracted from the stock price a proportion of the last dividend payment, which is the number of days since the last ex-dividend date divided by 90 representing a

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full quarter. Makholm PFT, pp. 32 and 33; Exhibit JDM-7.

Dr. Makholm stated that the DCF model requires that $D_1 = D_0 * (1+g)$, where D_0 is equal to the sum of the four most recent dividend payments. He obtained the sum of the past four quarterly dividends per share (DPS) payments from Value Line Investment Survey (Value Line) dated August 29, 2008, September 12, 2008, September 26, 2008, and November 7, 2008. He used the sum of the four most recent dividend per share payments for each utility in the comparable group, which is D_0 term for each utility in the comparable group. Makholm PFT, Exhibit JDM-8.

To estimate the dividend per share growth term g, Dr. Makholm used three different prospective growth measures from which he took the simple average. The first measure is of sustainable growth that examines projections of the separate components of dividend growth. This is retained earnings and expected returns to book equity, as well as the possibility of issuing new shares at prices in excess of book values. The second measure is calculated using the forecasts of earnings per share (EPS) published by Value Line. The third measure uses analysts' estimates of earnings as compiled by Zacks. Makholm PFT, p. 33.

The first method Dr. Makholm used to examine growth for his comparable companies, as a proxy for Southern, was the retention growth or sustainable growth methodology. This methodology produces a forward looking, sustainable growth rate by multiplying the fraction of earnings that analysts expect a company to retain by the expected return on book equity. The sustainable growth method also allows for growth stemming from new issuances of stock at premiums over book value. Dr. Makholm sees this method as a valid way of estimating future dividend growth. This is based on his supposition that future growth in the dividend can occur only if a portion of the expected equity return is reinvested instead of being paid out in the form of dividends or if new common stock is issued at prices above current book values causing existing shares to appreciate in value. Makholm PFT, p. 34.

Dr. Makholm estimated a sustainable growth rate for each utility in his comparable group using the following formula:

$$g = (B*R) + (S*V)$$

Where:
B = expected retention ratio
R = expected return on equity
S = percent new equity expected
V = 1 minus book-to-market ratio
Makholm PFT, p. 34.

Dr. Makholm stated that the above formula shows that investors can expect growth through both retained earnings and the sale of new common stock at a premium of book value. For all of the utilities in his comparable group, investors can at present expect both forms of growth since the market to book ratio for all of them is above one. The sustainable growth rate, that is BR + SV, should be implemented with financial ratios anticipated in the future. This rate is based solely on Value Line projected data for 2011 through 2013 for the return on common equity, estimated DPS, and estimated book value per share (BVPS). Makholm PFT, p. 34. His calculations of the sustainable growth rate show an average of 6.07% for the utilities in his comparable group. Makholm PFT, Exhibit JDM-9, p. 1.

A second method Dr. Makholm used to estimate growth is earnings forecasts from Zacks. His estimated long-term earnings per share (EPS) growth rate of the next five-years as reported by Zacks accessed on November 19, 2008 are 6.74%. Makholm PFT, Exhibit JDM-11, p. 1. Zacks is a firm that collects the growth rate estimates of financial analysts and publishes consensus growth rate information. Current stock prices and the DCF cost of equity are influenced by widely distributed forecasts such as Zacks. Makholm PFT, p. 35.

A third method Dr. Makholm used to estimate growth is Value Line EPS for the forecasted period 2011-2013 taken from The Value Line Investment Surveys dated August 29, 2008, September 12, 2008, September 26, 2008 and November 7, 2008, which is 7.20%. Makholm

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PFT, Exhibit JDM-11, p. 1. Value Line is the most widely subscribed service of its type and in addition Value Line does not sell stock but analysis of stock. Value Line is a highly regarded source of financial data that is used in utility rate cases. He concludes that due to the widespread use of Value Line among investors and its subscription driven independence, it should be included along with other sources as a reflection of investor perceptions. Makholm PFT, p. 36. To further support Value Line, Dr. Makholm cites a study by L.D. Brown and M.S. Rozeff, "The Superiority Analyst Forecasts as Measures of Expectations: Evidence From Earnings,"Journal of Finance, March 1978, pp. 1-16. It shows Value Line analysts make better forecasts than could be obtained by employing historical data only. In addition, he cites the Research Foundation of CFA Institute that "[a]nother unique and desirable feature of Value Line data is the breadth of forecasts reported. When a Value Line analyst updates coverage of a given stock, the analyst provides annual estimates of many different measures, including sales, operating margins, net profit margin, tax rates, cash flows, capital investments, earnings, and dividends."It is Dr. Makholm's conclusion that independent experts use Value Line in a number of ways due to this breadth of information and forecasts. Makholm PFT, pp. 36 and 37.

Dr. Makholm made an adjustment to his DCF model for selling and issuance costs. He reasons that such an adjustment is necessary since the issuance of common equity, as well as long-term debt and preferred stock involves costs, which are often measured as a percentage of the total debt, preferred equity, or common equity issuance. Due to these issuance costs the net proceeds are less than the total purchase price of a debt, preferred equity or common equity issuance. Unless an adjustment is made to determine a fair rate of ROE, the resulting equity determination will be to low. He makes the point that an adjustment is made to factor in selling and issuance costs as a part of computing the cost of debt and preferred stock and as such is appropriate for equity issuances as well. The practice of many utility commissions is to include a return element for selling and issuance expenses on equity in much the same way that a return component is included for such expenses with debt. The difference between the treatment for debt and equity is that the debt selling and issuance expense principal is amortized over the term of the debt issuance. However, since equity has no specific term, there can be no amortization of the principal and as such an equity rate of return component is necessary to reflect a holding charge. Makholm PFT, pp. 37 and 38.

Dr. Makholm stated that the most common method to compensate utilities common stock issuance costs as well as preferred stock and long-term debt is to allow a return on these costs for any one year and a return of these costs over the life of the issuance. For common stock since the life of the issuance is in essence perpetual the return component to recover the return on these costs is permanently a part of the ROE. These costs will only "go away" if they are paid off as a current expense. If a utility is not compensated for its issuance costs, it will result in the under-recovery of prudently incurred costs of raising capital. Makholm PFT, p. 38.

Dr. Makholm finds there are three methodologies to deal with compensating a utility for issuance costs. The first is to allow the utility to recover these costs automatically in the year they are incurred as an expense component of the revenue requirement or the expense could be amortized over a number of years with a return on the outstanding balance. A second method is to allow the issuance costs to be included in rate base such as is done for interest charges on construction work in progress. This enables the utility to earn a return on the costs as opposed to a return of the costs. The third method adjusts the cost of capital upward over the life of the issuance. This adjustment therefore allows the utility to earn a return on the issuance costs even though the costs are not in the rate base. As such the financial result and the revenue requirement are the same as in the second method. Makholm PFT, pp. 38 and 39.

The formula used by Dr. Makholm to calculate his issuance and selling expense adjustment is:

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Where:

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r = required return adjusted for issuance expenses
f = flotation cost percentage
Makholm PFT, pp. 39 and 40.

To choose an appropriate value for f the flotation cost percentage, Dr. Makholm used data from a publication by Victor Borun and Susan Malley who concluded that total flotation costs for electric utilities are approximately 5.50%. In addition, he also used data from the Southern's last four equity offerings and an equity offering from Connecticut Energy Corporation, the parent of Southern, taking the simple average of 5.21%. Makholm PFT, Exhibit JDM-12. Dr. Makholm averaged these two percentages for a 5.36%, which he concluded is the issuance cost percentage that should be used in his DCF calculation. Makholm PFT, p. 40.

It is Dr. Makholm's opinion that this issuance cost adjustment should be made to the total equity component in the capital structure. Investors are entitled to earn the expected cost of capital on their investment, which the DCF formula shows this expected cost is equal to dividend payments in addition to capital gains on the value of their shares. The cash investors pay in is greater than the net proceeds the company takes in. Therefore, the company must earn a greater return on the smaller net proceeds balance to compensate investors adequately for their expected cost of capital. However, the funds paid to investors in any given year of dividends reflect only a portion of the ROE. The other portion is retained earnings, which are the funds used to finance future growth and future dividends. If retained earnings do not receive a selling and issuance return adjustment, they will not be able to grow at a rate sufficient to allow for the payment of dividends at investors' expected growth rate in the future, then the company would not earn its true cost of capital. Makholm PFT, p. 40.

Dr. Makholm used the above factors in his final DCF formula calculation. He combined the ex-dividend date adjusted stock prices for November 18, 2008, the most recent four actual dividend per share payments, the average of the sustainable growth and forecast earnings estimates, and the issuance cost adjustment to produce a cost of common equity for the proxy group of 10.81%. Makholm PFT, Exhibit JDM-13.

iv. CAPM

Dr. Makholm's second methodology to calculate the cost of common equity to Southern is the CAPM. He stated that the CAPM is the sum of two components: (1) a risk free rate applicable to all companies (R_f); and (2) a company specific risk premium, which is the product of a company specific beta (B) and a market risk premium (R_m). Dr. Makholm's approach to implementing the CAPM includes: (1) relying on betas that are published in Value Line, which he characterizes as an independent source of financial information; and (2) calculating a top-down DCF analysis for the S&P 500 as a whole, which he believes provides an objective, and forward looking equity risk premium in the market. When his forward looking R_m is incorporated into the CAPM together with Value Line betas and the risk-free rate, this produces a timely and forward looking estimate of the cost of equity. He postulates that in times of unsettled markets, such as in the present, this approach has the decided advantage of relying on up to date information from close observers of the financial markets, rather than depending on historical data. Makholm PFT, pp. 41 and 42.

Dr. Makholm used a risk free rate of 4.17%, which is the yield on 30-year US Treasury bonds on November 12, 2008 reported in the Value Line Selection and Outlook dated November 21, 2008. In addition, he used Value Line betas for the companies in his comparable group. He reports that Value Line data is unique because Value Line"is not affiliated with any bank, broker, or insurance company."Further, the Research Foundation of CFA Institute explains that:
The corporations whose stocks are covered compensate neither Value Line nor the individual analysts following the company. All Value Line revenues come from fees collected from subscribers. As a result of this independence, any bias in Value Line analyst forecasts cannot be attributed to analyst desires to attract revenue-generating business in the form of investment banking fees or brokerage commissions.
Makholm PFT, p. 42.

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Dr. Makholm also used forward looking measures of the market risk premium by calculating a forward looking market risk premium through subtracting the risk free rate from estimates of the top-down cost of equity capital of the S&P 500. Data from First Call and Reuters show 10.68% and 11.27% top down estimated five-year earnings growth rates for the S&P 500 and S&P provides a 2.83% estimate of the current dividend yield of the S&P 500. He combined these inputs, using the standard DCF model, to calculate two estimates for a forward looking top down DCF cost of common equity for the S & P 500 of 13.99% using First Call data and 14.60% using Reuter's data. Makholm PFT, pp. 42 and 43 and Exhibit JDM-15. This method of calculating the risk premium using First Call data produces a 12.03% result for the comparable group. Using Reuter's data produces a 12.51% result for the comparable group. Makholm PFT, p. 43; Exhibit JDM-14, pp. 1 and 2. Dr. Makholm's concludes that his use of two approaches to estimate a CAPM cost of common equity for his comparable group produces a cost of equity range from 12.03% to 12.51%. Makholm PFT, Exhibit JDM-6.

v. Yield Plus Growth

To calculate YPG, Dr. Makholm added the expected dividend yield of the gas utility industry as published by Value Line of 4.60% to the expected growth rate for the gas utility industry as published by Reuters and First Call of 8.11% and 7.23%, respectively. This method calculated an investor expected cost of equity for the gas utility industry of 12.27%, which he used as a check on the indicated cost of equity of 12.20% from his DCF and CAPM calculations. Makholm PFT, pp. 43 and 44, Exhibit JDM-16, p. 1.

Dr. Makholm reasoned that due to the current credit crisis, it would be best to use widely available capital market publications of the yield and growth estimates for the regulated gas utility industry that would be readily available to investors. The yield of 4.60% and growth projections of 8.11% and 7.23% forming the basis of the 12.27% cost of equity is a confirmation to his calculation of 12.20% as a reasonable cost of equity for Southern. Makholm PFT, p. 44.

Based on his analysis, Dr. Makholm concludes that a fair rate of return on common equity for Southern that is reasonable is 12.20%, which is within his calculated range of 10.81% to 12.51%. Makholm PFT, Exhibit JDM-6. This range is bounded by his DCF and CAPM analyses of a comparable group of U.S. LDCs and combination gas and electric utilities that are comparable to Southern's regulated utility operations. He asserts that the reasonableness of his 12.20% return on common equity recommendation is supported by his 12.27% result using a YPG method for the natural gas utility industry. It is further supported by Southern's goal of improving its bond rating over the next two to three years.

vi. Decoupling

Dr. Makholm recognized that Connecticut Public Act 07-242 requires a consideration of the potential effects of **decoupling** policies on the ROE, which states in part "[i]n making its determination on this matter, the department shall consider the impact of **decoupling** on the gas or electric distribution company's ROE and make necessary changes thereto."Makholm PFT, p. 44. Dr. Makholm believes that **decoupling** is fundamentally an incremental change in the way that a utility designs its rates or bills its customers. This incremental change in rate design and billing does not affect investor perceived **risk**, which they would require compensation for in the form of a ROE. As substantiation for his understanding of investor expectations on **decoupling**, Dr. Makholm cites an article from Standard & Poor's which states:

Decoupling separates retail distribution revenues from sales, and it's intended to encourage energy conservation and alternative energy resources, and reduce costs without rate hurting the utility's bottom line... Standard & Poor's does not expect **decoupling** to have a noticeable impact on the company's financial condition.

Makholm PFT, p. 46.

He stated S&P's statement of a lack of "a noticeable impact" shows that it recognizes that incremental changes in rate design and billing would not affect the cost of capital. As such, **decoupling** does not affect the **risk** that requires compensation to investors in the form of a

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ROE. Makholm PFT, p. 46. Dr. Makholm concludes that changes in rate design or billing practices from **decoupling** provides no justification as a pretext for lowering a commission's awarded fair rate of return. He asserts that these two concepts have never been linked in the past in the capital markets. There is no evidence, or change in the markets perception of utilities that would validate such a reduction in ROE at the present time. Makholm PFT, p. 45.

Dr. Makholm provided his insight into the concept of risk as it relates to the cost of capital. He believes that two forms of risk influence the cost of capital and, therefore, should be taken into consideration when determining the cost of capital. These risks are:
1. Business risk accounted for by the use of proxy groups of companies in a like business to that of the company in question (in this case gas distribution).
2. Financial risk accounted for by checking the debt ratios of the companies in those groups to see if they are consistent with the company in question.
Makholm PFT, p. 45.

Dr. Makholm believes that business and financial **risk** are the only two **risks** that affect the cost of capital. Analysts stray from the above two definitions of **risk** when they use the term " **risk**" in describing **decoupling** primarily because there is no explanation as to what **risk** was meant. As an example, he uses the " **risk**" a LDC faces if it is a warm winter. That " **risk**" is readily counterbalanced by the " **risk**" of a cold winter. The unpredictability of weather from season to season collapses to a well known average after a number of years. Another example, Dr. Makholm uses is if it is " **risk** of revenues dropping due to customer conservation," then that " **risk**" can be counterbalanced by the " **risk** that the company will alter its tariff structure or file more frequent rate cases to deal with the trend of declining use."He concludes that these are loose uses of the term **risk**, and do not fit the definition of business **risk** or financial **risk** that drives the cost of capital. Makholm PFT, pp. 45 and 46.

Another issue Dr. Makholm points to is the assumption that decoupling might affect a utility's cost of capital treats decoupling as a specific change in business practices, which he believes it is not. Decoupling merely describes a movement away from traditional volumetric rates for a fixed cost service. There is no basis, either empirically of conceptually, for treating decoupling as a particular reason that requires a generic adjustment for the cost of equity. Since a proper ROE analysis depends on evidence, any assumption that a downward adjustment to the ROE is required to reflect decoupling is inappropriate. Makholm PFT, pp. 47 and 48.

Dr. Makholm's analysis of traditional gas distribution charges finds that these charges are not well suited to the needs of a contemporary LDC. He argues that LDCs in the major cities of the U.S. are over 150 years old and only for the past 50-60 years have they sold natural gas produced by others. For most of their history, they manufactured their own natural gas. The sale of their manufactured gas was their major business while distributing it was a secondary consideration. To this day, gas meters and the structure of gas distribution tariffs are a reflection of this history. For the majority of gas customers, their meters record monthly gas volumes and the distributors' revenues are mainly collected through these monthly volumetric meter readings. However, present day gas distribution is primarily a fixed cost business. The gas commodity costs for customers are tracked and billed in a separate mechanism through the PGA clause from that for the distribution charges. The meters record actual gas volume used, which allows for billing for the actual amount of gas commodity used. Dr. Makholm suggests that gas usage has little to do with the cost of maintaining and operating the gas network that is available to distribute the gas. Makholm PFT, pp. 47 and 48.

Dr. Makholm asserts that this disconnect between the costs of maintaining the distribution network is not reflected in the way that Southern bills its customers due to the manner in which rates are formulated in a rate case. This rate formulation involves dividing its just and reasonable cost of service by its expected billing volumes. Under this methodology, Southern is required to predict volumes for the period of time rates will be in effect using normal weather as well as expected customer usage. Two factors affect this, which are temperature

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and customer conservation of gas. Makholm PFT, p. 48.

Dr. Makholm reasons that while decoupling may decrease Southern's revenue swings, it will not affect its cost of capital since swings in revenue will normalize around the average level either with respect to temperature or to reasonable utility costs of serving customers. Any particular winter or couple of winters can be substantially colder or warmer than normal; however, all Southern has to do is wait for cumulative winter weather to return to normal. The working capital requirements associated with yearly weather swings are manageable for a reasonably financially healthy local gas distributor. Typically, LDCs are historically financially secure, robust companies that have been operating for many years. Swings in revenue due to weather and other factors do not typically harm LDCs such as Southern. Dr. Makholm brings out the point that LDCs such as Southern make a point to inform the credit rating agencies relative to which component of earnings swings are weather related (and therefore will change when the weather will inevitable changes around the known average) and which are not weather related. Makholm PFT, pp. 48 and 49. It is always possible that a LDC, for some reason other than weather, has lost its access to credit and requires the immediate cash a cold winter brings in to prevent default. In such a case, it is theoretically possible that a warm winter could push a LDC over the edge into default due to lack of adequate cash flow. However, the adjustment mechanism that Southern is proposing in the instant case would not help to any significant degree for a LDC on the edge of default. Makholm PFT, p. 49.

Dr. Makholm claims that a fundamental and commonly accepted principle of financial markets is that investors need not be compensated for **risks** that diversification can remove. Finance principles tell us that investors only require compensation for those **risks** that diversification cannot handle. Deviations in revenues due to weather around a known average are easily diversifiable. The LDCs deal with weather related fluctuations in revenue with a combination of working capital and short-term debt. As such, Dr. Makholm asserts that whether a LDC has or does not have a **decoupling** clause has nothing to do with the cost of capital.

Dr. Makholm addresses the issue of the trend of declining gas use per customer. This has become evident in the past few years due to customers working to conserve gas usage due to a rise in the real price of gas. He cites research from his article "Decoupling for Energy Distributors: Changing 19th Century Tariff Structures to Address 21st Century Energy Markets" in the Energy Law Journal. It shows that, nationwide, while the average use per customer of electricity continues to rise, the average gas use per customer has been dropping since the 1980s with the expectation that it will drop further. The decline over the country is not uniform. Some LDCs in the Southwest in rapidly growing areas have not seen the decline. The decline is most pronounced in those regions of the country with well built up and mature service territories such as Southern. Dr. Makholm finds that there is no evidence that this long-term declining trend in gas use per customer affects credit ratings or the cost of capital. The lack of an empirical tie between decoupling and the cost of capital is what he would expect. The extent to which a LDC can track this element of gas usage as part of its two-pronged approach to create the most cost reflective and non-customer use sensitive distribution tariffs has nothing to do with its financial health. What it does is remove a source of regulatory lag that may prevent the more rapid filing of another rate case. Makholm PFT, p. 50.

vii. Supplemental Supply Cost Recovery Mechanism

Dr. Makholm's analysis of Southern's requested SSCRM proposal shows it to be an expense recovery item and also a billing issue. The SSCRM reflects gas costs which are volatile having recently been high and now have been driven downward reflecting both the supply and demand balances of gas and the current weak economic environment. Rather than trying to predict a forecast of SSCRM costs in the future, Southern admits that this is not practical given the volatility in the gas market. Absent such a forecast, Southern proposes to track the SSCRM costs as they occur and defer the differences between the amount embedded in base delivery rates and the actual costs. Makholm PFT, pp. 50 and 51.

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Dr. Makholm views Southern's SSCRM proposal as an attempt to address a cost of service that is highly unpredictable due to the volatility of the cost of gas, which is outside Southern's ability to control or predict. Increasing SSCRM costs produce a schism between Department approved revenues and the opportunity for Southern to collect them. Southern believes that the SSCRM is the least problematic to implement relative to the alternatives to deal with the issue. Makholm PFT, p. 51.

Dr. Makholm's description of the background leading to Southern's SSCRM proposal is centered on the unpredictable cost items. The gas cost adjustment was created decades ago due to concerns of rising gas costs that could hurt a LDC's creditworthiness. Unless LDCs were able to pass on such costs on a timelier basis without the regulatory cost of filing a base rate case. In the 1970s, the use of gas adjustment clauses became more common place as both shortages and the problems associated with natural gas well head price decontrol contributed to drive gas prices quickly upwards. Makholm PFT, p. 51.

Dr. Makholm believes that the automatic adjustment rationale used for the potential increase of gas costs also applies to the SSCRM issue. Southern proposes to defer SSCs as a distribution expense similar to the treatment of gas costs. The difference between the two is the treatment and timing of the collection or return of the costs. Rising gas commodity prices and the resulting rising customer bills for the gas commodity secured by Southern for their customers affect gas working capital, commodity related uncollectibles, and gas inventory charges raising these above long-term historical averages. Makholm PFT, p. 51. As an answer to the volatility of gas costs flowing through to the SSCRM, Southern proposes to track the actual SSCRM costs such that the actual and prudent cost of service for an item that is expected to deviate sharply from historic averages. A basic tenant of ratemaking is a utility is given the opportunity to collect the entirety of its prudent cost of service including such items as bad debts. Southern concluded in the instant case that tracking this volatile element of cost through the SSC is a less expensive method to deal with the issue then the prospect of having it contribute to an earlier rate case with which Dr. Makholm is in agreement. Makholm PFT, p. 52.

Dr. Makholm concludes that tracking bad debts through the SSCRM allows Southern to recoup a legitimate cost of providing service to the public. The SSCRM will not affect the cost of capital for Southern in that the cost of capital is driven by investors' perception of business and financial risk, which are not affected by the SSCRM rider. Investors have a well informed expectation that fewer customers will pay their current bills than paid in the past, which is common for LDCs generally in the U.S. in 2008. Makholm PFT, pp. 52 and 53.

d. Summary of Dr. Woolridge's Testimony

i. Overview

Dr. Woolridge evaluated Southern's cost of equity and determined a fair rate of return on common equity for the Company to be 9.00% based on applying the DCF methodology and the CAPM. As a check, he examined the relationship between the return on common equity and the market-to-book ratios for the utilities in his comparable group. This fair rate of return lies within the broad range of 7.00% to 9.60% indicated by his analysis. Dr. Woolridge used an equity cost rate at the upper end of the range in recognition of the volatile capital markets conditions. Woolridge PFT, p. 3.

ii. Selection of a Comparable Group

As the first process in determining Southern's cost of equity, Dr. Woolridge formed comparable group of nine natural gas distributors using the following selection criteria:
1. Listed as a natural gas distribution, transmission, and/or integrated gas company in AUS Utility Reports.
2. Listed as a natural gas utility in the standard edition of the Value Line Investment Survey.
3. At least 50% regulated gas revenues.
4. An investment grade bond rating by Moody's and Standard & Poor's.
Woolridge PFT, p. 16.

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The companies meeting these criteria are AGL Resource, Atmos Energy, Laclede Group, Nicor, Inc., Northwest Natural Gas Company, Piedmont Natural Gas Company, South Jersey Industries, Southwest Gas, and WGL Holdings. The average operating revenues for this comparable group is $2,739.2 million and the average net plant is at $2,378.0 million. This comparable group, on average receives 69% of revenues from regulated gas operations, has an A3 Moody's bond rating, common equity ratio of 46% and an earned return on common equity of 11.6%. Woolridge PFT, pp. 16 and 17.

iii. DCF Model

Dr. Woolridge's DCF analysis employed three data inputs of stock price P_o, the current annual dividends D_o, and estimated dividend growth rates for each of the utilities in his comparable group. He calculated the dividend yield, for his proxy group, using the 6-month period September 2008 through February 2009 which is 4.25%. Woolridge PFT, pp. 32 and 33.

This 6-month dividend yield was then adjusted since under the traditional DCF model the dividend yield term relates to the dividend yield over the coming period. This is calculated by multiplying the expected dividend over the coming quarter by four and dividing this dividend by the current stock price to determine the appropriate dividend yield for a company that pays dividends on a quarterly basis. Dr. Woolridge reports that some analysts adjust the current dividend over the coming year as opposed to the coming quarter. The complication in this is that companies announce changes in dividends at different times during the year. Considering these differences in methodology, the dividend yield, computed based on presumed growth over the coming quarter as opposed to the coming year, can be quite different. As a result, it is common for analysts to adjust the dividend yield by some fraction of the long-term expected growth rate. In his analysis, Dr. Woolridge adjusted the dividend yield by one-half of the expected growth rate to reflect growth over the coming year. Woolridge PFT, pp. 33 and 34.

For the growth rate used in the DCF, Dr. Woolridge stated that "[t]here is much debate as to the proper methodology to employ in estimating the growth component of the DCF model."Woolridge PFT, p. 34. Investors use a combination of historical and/or projected growth rates EPS, DPS, and for internal or book value growth to assess the long-term prospective of a company. Woolridge PFT, p. 34.

Dr. Woolridge analyzed an array of measures of growth for each of the utilities in his comparable group. He reviewed Value Line's historical and projected growth rate estimates for EPS, DPS, and BVPS. Further, he considered the average EPS growth rate forecasts of Wall Street analysts as published by Bloomberg and Zacks, which are services that solicit five-year earnings growth rate projections from securities analysts. These services compile and publish the means and medians of these forecasts. In addition, Dr. Woolridge evaluated prospective growth as measured by prospective earnings retention growth rates and earned returns on common equity. Woolridge PFT, p. 34.

Dr. Woolridge stated that historical growth rates for EPS, DPS, and BVPS are easily obtainable by investors and seemingly a significant component in determining expectations in relation to future growth for a company. However, he warns that the use of historical growth numbers as measures of investors' expectations must be used with caution. There are some cases where past growth may not reflect probable future growth potential. In addition, using a single growth rate number such as five or ten years is unlikely to accurately measure investors' expectations. This is due to the sensitivity of a single growth rate figure to fluctuations in individual company performance as well as overall economic fluctuations such as business cycles. However, Dr. Makholm cautions that it is necessary to evaluate the background in which the growth rate is being employed. Woolridge PFT, p. 35.

By the definition of the conventional DCF formula, the expected growth rate must be appraised in the context in which the growth rate is being used. The conventional DCF model calls for the expected return on a security to be equal to the sum of the dividend yield and the expec-

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ted long-term growth in dividends. For that reason, the optimal estimate of the cost of common equity using the conventional DCF model requires the analysis to evaluate long-term growth rate expectations. Woolridge PFT, p. 35.

One such long-term growth rate expectation is internally generated growth as a function of the percentage of earnings retained within the firm known as the earnings retention rate and the rate of return earned on those earnings known as the ROE. Internal growth is calculated as the retention rate times the Roe, which is significant in determining long-term earnings and therefore dividends. Dr. Woolridge postulates that investors recognize the importance of internally generated growth and, therefore, pay premiums for stocks of companies that retain earnings and earn high returns on internal investments. Woolridge PFT, pp. 35 and 36.

Dr. Woolridge did not rely exclusively on the EPS forecasts of Wall Street analysts to develop the growth rate in his DCF analysis for his comparable group for several reasons. The appropriate growth rate in the DCF model is the dividend growth rate not the earnings growth rate. However, he stated that dividend and earnings will grow at a similar growth rate over the very long-term. Therefore, he concludes that other indicators of growth including prospective dividend growth, internal growth, and projected earnings growth should also be considered. Woolridge PFT, p. 36.

Dr. Woolridge collected historical growth data for his comparable group from Value Line of earnings, dividends, and book value for both the past ten years and the past five years. He stated that due to the presence of outliers in the historic growth figures, he used both the mean and median in his analysis. These outliers are data points that are much larger or smaller than the majority of the data points that are being analyzed. The historic growth measures in EPS, DPS, and BVPS, for his comparable group, as measured by the means and medians range from 1.5% to 7.4% with an average of 4.2%. Woolridge PFT, pp. 36 and 37, Exhibit JRW-10, p. 3.

For projected growth rates, Dr. Woolridge used Value Line's projections of EPS, DPS, and BVPS for each of the utilities in his comparable group. Due to the presence of outliers, he used both the means and medians in his analysis, which show a central tendency measures that range from 3.3% to 5.2% with an average of 4.3%. Woolridge PFT, p. 37; Exhibit JRW-10, p. 4. Another measure of growth employed by Dr. Woolridge is prospective internal growth for the comparable group as measures by Value Line's average projected retention rate and return on stockholders' equity. This is an important measure since internal growth is a primary driver of long-run earnings growth. The average projected internal growth rate for his comparable group is 5.6%. Woolridge PFT, p. 37, Exhibit JRW-10, p. 4.

Lastly, Dr. Woolridge assessed his comparable group growth rate, as measured by analysts' forecasts of projected five-year EPS growth. The primary services that collect, summarize, and publish Wall Street analysts' five-year EPS growth rate forecasts for his comparable group is Zacks, Yahoo!/First Call, and Bloomberg. The mean and median of analysts' projected EPS growth rates for his comparable group is 5.7%. There is considerable overlap in analyst coverage between the three services, and not all of the companies have forecasts from the different services. Consequently, he averaged the expected five-year EPS growth rates from the three services for each utility to arrive at an expected EPS growth rate by utility, which calculated to 5.7%. Woolridge PFT, pp. 37 and 38, Exhibit JRW-10, p. 5.

Dr. Woolridge analyzed these various growth rates for his comparable group. The average of the growth rate indicators for his comparable group is 4.7%. The average of the projected and prospective internal growth rate indicators is 5.2%. He gave greater weight to the projected and prospective internal growth rate indicators. He found that an expected DCF growth rate in the 5.0% to 5.5% is reasonable for his comparable group. He used the midpoint of this range of 5.25% as the expected growth rate in the DCF calculation for his comparable group. Woolridge PFT, p. 38; Exhibit JRW-10, p. 6.

In summary, Dr Woolridge combines these various elements of the dividend yield, adjustment to the dividend yield and growth rate to calculate a DCF allowed return

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on common equity of 9.6%. This is shown in the following summary:

Dividend Yield	4.25%
Adjustment Factor	1.02625
Adjusted Dividend Yield	4.35%
Growth Rate	5.25%
DCF Equity Cost Rate	9.60%

Exhibit JRW-10, p. 1.

iv. CAPM

As a second method to calculating an allowed ROE, Dr. Woolridge used the CAPM, which is a risk premium approach to estimating a company's cost of equity capital. According to the CAPM, the expected return on a company's stock, which is also the equity cost rate (K), is equal to:

$$K = (R_f) + B * [E(R_m) - (R_f)]$$

Where:
1. K represents the estimated rate of return on the stock.
2. $E(R_m)$ represents the expected return on the overall stock market. Frequently, the market refers to the S&P 500.
3. (R_f) represents the risk free rate of interest.
4. $[E(R_m) - (R_f)]$ represents the expected equity or market risk premium which is the excess return that an investor expects to receive above the risk free rate for investing in risky stocks.
5. (B) Beta is a measure of the systematic risk of an asset.
Woolridge PFT, p. 40.

The calculation of the required return or cost of equity using the CAPM requires three inputs: the risk-free rate of interest (R_f), the beta (B), and the expected equity or market risk premium $[E(R_m) - (R_f)]$. The risk free interest rate in the CAPM has long been viewed as the yield on long-term U.S. Treasury bonds. The term long-term yield on Treasury bonds has long been thought of as the yield on U.S. Treasury bonds with 30-year maturities. However, when the Treasury interrupted the issuance of 30-year bonds for a period of time in recent years, the yield on 10-year U.S. Treasury bonds replaced the yield on 30-year U.S. Treasury bonds as the benchmark long-term Treasury rate. Over the last five years, the 10-year Treasury yields show volatility. These rates hit a 60 year low in the summer of 2003 at 3.33%. In recent years, they increased with the rebounding economy and fluctuated in the 4.0% to 5.0% range. Due to a strong economy as well as increases in energy, commodity, and consumer prices, the 10-year Treasuries advanced to 5.0% in early 2006. In late 2006, long-term interest rates retreated to the 4.5% area due to a decline in commodity and energy prices and inflationary pressures easing. In the first half of 2007, these rates rebounded to the 5.0% level. In mid-2007, 10-year Treasury yields began to decline due to the beginning of the current financial crisis. They have fallen below 3.0% as the housing and sub-prime mortgage crisis have led to an overall credit crisis and economic recession. Woolridge PFT, p. 41, Exhibit JRW-11, p. 2.

Dr. Woolridge reports that the U.S. Treasury began to issue 30-year bonds in the early 2000s as the U.S. budget deficit increased at which time the market once again focused on its yield as the benchmark for U.S. long-term capital costs. Yields on the 10- and 30- year U.S. Treasuries decreased to below 5.0% in 2007 and have remained at these lower levels. Treasury yields were pushed even lower in 2008 due to the mortgage and sub-prime market credit crisis, financial sector turmoil, uncertainty of the length of the recession, and the government bail out of financial institutions. For these reasons, there has been a flight to quality in the bond

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market, which has driven Treasury yields to historic lows. As of February 16, 2009 rates on 10- and 30- year Treasury Bonds were 2.89% and 3.67% respectively. However, over the past three months these rates have been highly volatile. Due to this recent range and volatility, along with the trend of increasing 30-year Treasury yields, a long-term Treasury rate in the 3.5% to 4.0% range is reasonable for the near term future. He used the midpoint of this range of 3.75% as the risk free rate of R_f in his CAPM. Woolridge PFT, pp. 41 and 42.

For the measure of beta (*B*), Dr. Woolridge used the betas for each of the utilities in his comparable group as published by Value Line. Beta is a measure of the systematic risk of a stock. The calculation of beta is performed through a linear regression of a stock's return on the market return. The market is generally defined as the S&P 500, which has a beta of 1.0. A stock exhibiting price movement greater than that of the market is considered riskier than the market and has a beta greater than 1.0. A stock with price movement less than the market is considered less risky than the market and has a beta less than 1.0. Dr. Woolridge stated that there are numerous online investment services such as Yahoo! And Reuters which supply stock betas which often times report different betas for the same stock. The reason for these differences are the time period over which the beta is measured and any adjustments that are done to reflect that betas tend to regress to 1.0 over time. The betas for his comparable taken from Value Line are at an average of .70. Woolridge PFT, pp. 42 and 43; Exhibit JRW-11, p. 3.

The equity or market risk premium was calculated by Dr. Woolridge using the formula $[E(R_m) - (R_f)]$, which is equal to the expected return on the stock market using the proxy of the S&P 500 $[E(R_m)]$ minus the risk free rate of interest (R_f). The equity premium is the difference in the expected total return between investing in equities and investing in "no risk" or "safe" fixed income assets such as long-term government bonds. He asserts that the equity risk premium is easily defined conceptually but the difficult task is to measure it since this requires an estimate of the expected return on the market. Woolridge PFT, pp. 43 and 44.

Dr. Woolridge measured the equity risk premium using the following methodologies:

1. Historic Ex Post Returns - This traditional methodology to measure the equity risk premium uses the difference between historical average stock and bond returns. These historical stock and bond returns also known as ex post returns were used as measures of the market's expected return which is also known as the ex ante or forward-looking expected return. Dr. Woolridge used several ex post studies to calculate a simple average of 5.39% equity risk premium.
2. Ex Ante Models - This methodology is forward looking and computes ex ante expected returns using market data such as expected earnings and dividends to arrive at an expected equity risk premium. Dr. Woolridge used several ex ante studies to calculate a simple average of 4.48% equity risk premium.
3. Surveys - This methodology uses estimates equity risk premium through the use of surveys of investors and financial professionals. Dr. Woolridge used several surveys to calculate a simple average of 4.20% equity risk premium.
4. Building Block - This ex ante methodology combines variables which include inflation, real EPS and DPS growth, ROE and book value growth, and price earnings ratios. Dr. Woolridge combined a historic supply model building block done by Ibbotson and Chan and also developed his own current supply model building block to calculate a simple average of 4.71% equity risk premium.

Woolridge PFT, pp. 43-58, Exhibit JRW-11, p. 6.

He combined these various methodologies to produce an equity risk premium of 4.69%. Combining this with his other CAPM inputs in the formula $K = (R_f) + B * [E(R_m) - (R_f)]$ or $K = 3.75(R_f) + .70\ (B) * 4.69\% [E(R_m) - (R_f)]$ produces a 7.00% cost of equity. Woolridge PFT, Exhibit JRW-11, p. 1.

v. Return on Common Equity and Market to-Book Ratios

To test the reasonableness of his equity cost recommendation, Dr. Woolridge examined the relationship between the return on common equity and the market-

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to-book ratios for the utilities in his comparable group. The mean current ROE for his comparable group is 11.6% and the mean market-to-book ratio for his comparable group is 1.61. These results indicate on average that his comparable group is earning returns on equity above their equity cost rates. This observation leads Dr. Woolridge to the conclusion that his recommended equity cost rate is reasonable and fully consistent with the financial performance and market valuation of the comparable group of gas distribution companies. Woolridge PFT, pp. 61 and 62.

vi. Flotation Costs

Dr. Woolridge believes that an adjustment for selling and issuance costs, also known as flotation costs, is not necessary for Southern. These flotation costs are incurred when a company sells securities to investors. It is argued that if a company issues securities, a flotation cost adjustment is necessary to prevent dilution of the existing shareholders. This treatment is often justified by reference to bonds where issuance costs are recovered by including the amortization of bond flotation costs in annual financing costs. Woolridge PFT, p. 77.

The basis for Dr. Woolridge not including flotation costs in Southern's case is his reasoning that if an equity flotation cost adjustment is similar to a debt flotation cost adjustment then, since the market-to-book ratios for gas distribution companies are in excess of 1.60, this suggests that there should be a flotation cost reduction and not increase to the equity cost rate. The reason behind this is that when a bond is issued at a price in excess of face or book value and the difference between market price and the book value is greater than the flotation or issuance costs, the cost of that debt is lower than the coupon rate of that debt. He observes the amount by which market values of gas distribution companies are in excess of book values is much greater than flotation costs. Therefore, Dr. Woolridge reasons that if common stock flotation costs were exactly like bond flotation costs and if an explicit flotation cost adjustment was made to the cost of common equity, the adjustment would be downward. Woolridge PFT, p. 77.

Further, Dr. Woolridge stated that it is commonly argued that a flotation cost adjustment should be performed to prevent dilution of existing stockholders' investment. He argues that this reduction in a stockholders' investment can only occur when a company's stock is selling at a market price at or below its book value. In this instance, since LDCs are selling at 1.60 market-to book ratio, which is well in excess of book value. Due to this, when new shares are sold, existing shareholders realize an increase in the book value per share of their investment and not a decrease. Woolridge PFT, pp. 77 and 78.

Dr. Woolridge stated flotation costs are made up primarily of the underwriting spread or fee and not out-of-pocket expenses. On a per share basis, this underwriting spread is equal to the difference between the price the investment banker receives from investors and the price the investment banker pays to the company. He argues that because of this, these underwriting expenses should not be recovered through the regulatory process. In addition, the underwriting spread is known to investors who are purchasing the new issue of stock and are aware of the difference of the price they are paying to purchase the stock and the price the Company is receiving. When investors decide to buy a stock, it is the offering price that they pay that is important to them because their decision making is based on expected return and risk prospects. A company should not be entitled to an adjustment to the allowed return to account for these costs. Woolridge PFT, p. 78.

Dr. Woolridge believes that a more correct definition of flotation costs that are in the form of an underwriting spread are transaction costs in the market. He believes this since flotation costs represent the difference between the price paid by investors and the amount received by the issuing company. Dr. Woolridge likens transaction costs to brokerage fees that investors pay when they buy shares in the open market which are a market transaction cost. Since brokerage fees of investors are not included in determining an allowed ROE, then neither should flotation costs that are in the form of an underwriting spread. Woolridge PFT, pp. 78 and 79.

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vii. Decoupling

Dr. Woolridge stated that his recommended equity cost rate for Southern is 9.25% but only in the event that the Department does not include a **decoupling** mechanism in its final Decision. In his opinion, the adoption of such a mechanism would serve to reduce the volatility of a company's revenues and earned ROE and reduces the riskiness of a utility. Under the presumption that the Department includes a **decoupling** mechanism such as the one approved in the UI Decision, Dr. Woolridge recommends a 25 basis point reduction in the allowed ROE to reflect the reduction in **risk**. Woolridge PFT, p. 60.

Dr. Woolridge has not conducted any studies to ascertain the reduction in **risk** associated with **decoupling** nor is he aware of any such studies. He is aware that a number of state regulatory commissions have adopted **decoupling** ratemaking mechanisms for electric and gas companies. They recognized **risk** reduction as a consequence of **decoupling** mechanisms and, therefore, made an adjustment to the authorized ROE. Dr. Woolridge stated that these decisions indicate that an adjustment of up to 50 basis points is appropriate to recognize the **risk** reduction due to **decoupling**. Woolridge PFT, p. 60.

e. Department Analysis of Cost of Equity

i. Overview

The analyses undertaken by Dr. Makholm and Dr. Woolridge to determine the investor required ROE contained differences within the methodologies and employment of multiple methods of valuation. The principal issues between the studies performed by the two costs of capital witnesses concerned the yield calculation and growth rate used in the DCF model, the risk premium assigned to the Company's common equity and the level of reliance on each modeling method to determine overall valuation. The Department carefully reviewed and considered the testimony of the two consultants, and performed its own cost of capital calculations using data from the instant case and reliance on the body of past practice of the Department in valuating utilities.

The Company's primary argument for elevating its ROE to the requested 12.2% is that this level will result in the Company achieving an "A" bond rating, which the Company claims will lead to reduced cost of capital. Tr. 4/8/09, pp. 198 and 199; Tr. 4/20/09 p. 1774. However, the Company concedes that multiple factors, other than a regulatory imposed ROE, which are under the direct control of company management, also influence a company's bond rating. These factors include the company's: management and governance practices, level of uncollectable accounts, character of its services, and operating performance. Tr. 4/8/09 pp. 199-201; Tr. 4/20/09 pp. 1775 and 1776. The Company also stated that its long term goals could be served by maintaining its current bond rating of BBB+. RRP PFT, p. 59. During the hearing process, Dr. Makholm stated that he believed the suggested ROE of 12.2% would lead to an "A" bond rating "eventually." When asked how long it might take for the Company to achieve an "A" rating if the 12.2% rate were granted, Dr., Makholm replied "I don't know." Tr. 4/20/09, p. 1780.

Dr. Makholm developed a range for a fair rate of ROE of 10.81% to 12.51%. Makholm PFT, p. 2; Exhibit JDM-6. When asked to explain why 12.2% rather than the midpoint of his range (which is 11.66%) was appropriate, in addition to having difficulty calculating the midpoint of the range, Dr. Makholm's answer was; "12.2 was within the range, was lower than an independent check on the cost of equity, and was intended to help the company move out of a marginal rating category into a solid rating category. And in my opinion, it was a fair return to ask for in this proceeding."Tr. 4/20/09, p. 1774. The Department questioned Dr. Makholm further on his opinion regarding the possible existence of a causal relationship between a granted ROE and bond ratings. Based on his belief that a 12.2% ROE would lead to an "A" bond rating, Dr. Makholm was asked what ROE would be required to result in an A+ rating. His reply was, "[i]n my testimony, I don't make distinctions when I measure the credit ratings between the plusses or minuses of A or BBB." When asked a follow-up question on what ROE would lead to a bond rat-

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ing of AA, Makholm stated, "I don't examine AA bonds in this context."Tr. 4/20/09, pp. 1781 and 1782. Based on the thin arguments and contradictory testimony by the Company, the Department gives little weight to the Company's position that a 12.2% ROE will result in an "A" bond rating for Southern any time in the foreseeable future. If the Company wishes to elevate its bond rating, there are several performance metrics within the Company's control, to which it may apply its efforts.

ii. Comparable Group

The Department considered both comparable groups from Dr. Makholm and Dr. Woolridge. The Department used Dr. Woolridge's nine member comparable group consisting of the utilities AGL Resource, Atmos Energy, Laclede Group, Nicor, Inc, Northwest Natural Gas Company, Piedmont Natural Gas Company, South Jersey Industries, Southwest Gas, and WGL Holdings. Dr. Makholm's comparable group also included four utilities from Dr. Woolridge's group, which are Piedmont Natural Gas, Northwest Natural Gas, Southwest Gas, and Nicor, Inc.

Southern was critical of Dr. Woolridge's comparable group of LDCs stating that they have significant amounts of unregulated operations and, as such, are not comparable to Southern. Brief, pp. 26 and 27. The Department believes that the investment community considers Dr. Woolridge's comparable group to be LDCs since these utilities are each listed as natural gas distribution, transmission, and/or integrated gas companies in AUS Utility Reports and listed as natural gas utilities in the Standard Edition of the Value Line Investment Survey. See, Woolridge PFT, p. 16.

OCC argues that Dr. Makholm's comparable group of nine combination electric and gas companies is not appropriate. This is because their operating revenues are from sources other than regulated gas distribution utility services. Several of these companies have large revenues from electric utility operations. OCC contends that gas utilities are among the least risky industries as measured by beta and electric utilities are riskier. Therefore, Dr. Makholm's group should not be used as comparable group for Southern. Brief, p. 14.

The Department considered the criterion that assesses the risk and overall comparability to Southern for the nine member comparable group. These criteria are, being a natural gas utility subject to regulation from a state utility commission, common equity ratio, percentage of gas revenue from regulated operations, not involved in any acquisition or merger activity, operating revenues, and rating. The following table shows these criteria:

Gas Utility	Operating Revenue ($ million)	Percent Gas Revenue	S&P Bond Rating	Moody's Bond Rating	Common Equity Ratio
AGL Resources Inc.	2,680.0	65	A-	A3	41
Atmos Energy Corp.	7,221.3	51	BBB+	Baa3	45
Laclede Group, Inc.	2,209.0	51	A	A3	45
NICOR Inc.	3,665.3	84	AA	A1	50
Northwest Natural Gas Company	1,020.3	98	AA-	A2	47
Piedmont Nat.	2,089.1	75	A	A3	42

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Gas Co. Inc.					
South Jersey Industries Inc.	954.4	59	A	Baa1	50
Southwest Gas Corp.	2,195.6	83	BBB-	Baa3	45
WGL Holdings, Inc.	2,682.2	58	AA-	A2	52
Mean	**2,739.2**	**69**			**46**

The Department rejected certain companies in Dr. Makholm's comparable group, which are Alliant, Avista Corp., MGE Energy, NStar and Wisconsin Energy. The Department finds their risk comparability was not comparable to a regulated LDC such as Southern since these companies are combination electric and gas companies. The following table shows the percentage of gas revenues for each:

Utility	Percentage of Gas Revenues
Alliant	21
Avista Corp.	45
MGE Energy	37
NSTAR	18
Wisconsin Energy	35

Woolridge PFT, p. 66.
The Department finds that the above utilities, having less than 50% gas revenues, do not qualify as being comparable to a LDC such as Southern.

iii. DCF Model

To test the comparative validity of modeling presented by the witnesses, the Department performed its own DCF calculation using traditional DCF methodology. To develop the dividend yield of D_1/P_0 the Department used the dividend yields for the period November 2008 through April 2009 and the Department's modified comparable group. In its DCF calculation, the Department recognized that dividend yield is the most volatile component of the calculation, and therefore used a six-month average dividend yield. This is a long enough period to smooth out any stock aberrations but short enough to bring current information into the calculation. The Department used a six-month dividend yield in the Decision dated May 25, 2000 in Docket No. 99-09-03 and the Decision dated October 13, 1995 in Docket No. 95-02-07.The Department finds a spot yield should not be used since it is given to aberrations in that one day, which may not truly reflect investor stock price expectations. The Department stated this fact in the Decision dated October 13, 1995 in Docket No. 95-02-07"[a] three month and a spot yield are too short a duration to be as useful as a six month average."Decision, p. 75. The Department used recent data to reflect the current economic climate. The simple average of these dividend yields is 4.40%, which the Department adopts for the D_1/P_0 calculation. The specific dividend yields are as follows:

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Gas Utility	Nov. 2008	Dec. 2008	Jan. 2009	Feb. 2009	Mar. 2009	Apr. 2009	Mean
AGL Resources Inc.	6.0%	6.0%	5.7%	5.5%	5.7%	6.3%	5.9%
Atmos Energy Corp.	5.9%	6.0%	5.7%	5.6%	5.5%	5.7%	5.7%
Laclede Group, Inc.	3.1%	3.1%	3.4%	3.6%	3.6%	4.0%	3.5%
NICOR Inc.	4.4%	4.4%	5.2%	5.8%	6.1%	5.5%	5.2%
Northwest Natural Gas Co.	3.5%	3.5%	3.5%	3.8%	3.7%	3.6%	3.6%
Piedmont Nat. Gas Co. Inc.	3.4%	3.4%	3.4%	4.0%	4.1%	4.1%	3.7%
South Jersey Industries Inc.	3.4%	3.4%	3.2%	3.3%	3.2%	3.4%	3.3%
Southwest Gas Corp.	3.6%	3.6%	3.7%	3.7%	4.0%	4.7%	3.9%
WGL Holdings, Inc.	5.3%	5.3%	4.5%	4.5%	4.4%	4.6%	4.8%
Mean	**4.3%**	**4.3%**	**4.4%**	**4.4%**	**4.5%**	**4.7%**	**4.4%**

In choosing the growth rate, the Department used a combination of the Value Line projected growth in earnings of 4.60%, the internal growth methodology using Value Line numbers of 11.80% ROE and 44.6% retention growth for an internal growth rate of 5.2%, and historic five-year growth rate of 7.10%. The three growth figures calculated, 4.60%, 5.20% and 7.10% have a simple average of 5.63% [(4.60% + 5.20% + 7.10) / 3]. The average of the range is 5.85% [(4.60% + 7.10) / 2]. In comparing the simple average with the range average, the Department notes that the historic five-year growth rate is the outlier, and has selected a growth rate (g) nearer the midpoint of the range for use in the DCF calculation. The growth rate figure used by the Department is 5.46%.

The Department is aware of Southern's preference for projected growth rates. Southern stated that consistent with the requirements of the Hope Decision, returns must be sufficient to attract capital. Growth levels must be based upon investors' expectations of growth, rather than historical growth. The Department believes that investors consider past performance in evaluating the future as well as analyst forecasts. These serve to provide an insight for investors of the macro economic impacts on growth as well as the micro economic impacts for the individual utility. The Department used Value Line since it is a well respected source of investor information. In addition, the Department adjusted the dividend yield by one-half of the expected growth rate to reflect growth over the coming year.

Combining the dividend yield and growth rate is shown in the following:

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Dividend Yield	4.40%
Adjustment Factor	1.02815
Adjusted Dividend Yield	4.52%
Growth Rate	5.46%
DCF Equity Cost Rate	9.98%

Dr. Makholm also employed a variation on the DCF model, which he calls "Yield Plus Growth." The primary difference between the DCF model and the YPG model being the addition of the assumed dividend yield of the gas utility industry. The Department considers the YPG model to be a variant of the DCF model, and has not previously recognized the employment of the YPG model in any rate case Decision for rate-making purposes. Tr. 4/20/09, p. 1797; Response to Interrogatory GA-114.

The Department's primary purpose in developing its DCF model was to test the validity of the witnesses' testimony, not to endorse that method's use in this docket. The DCF model, and its derivative, the "Yield Plus Growth" model introduced by Southern's witness Dr. Makholm, are not ideal modeling methods for the instant case. The DCF model is most applicable to the valuation of stock when the company in question is a large firm with a stock in public trade. The DCF becomes increasing less useful as an evaluation tool when the company being considered is smaller in size and/or when the company's stock is thinly traded, or so closely held as to be effectively unavailable for trade. See, Decision dated August 13, 2008 in Docket No. 08-03-19,Application of The Torrington Water Company for Amendment of Rate Schedule, p.35.

The Department believes that the DCF model may yield wildly fluctuating outputs based on input variations. The DCF model is particularly vulnerable to output error when small variations to its two primary inputs, earnings per share and the discount rate, are manipulated. Although the witnesses for Southern and OCC both used a proxy group to project an estimate representative of the business risk of Southern, the DCF model itself is not ideal as a predictor in this rate case. Both Dr. Makholm and Dr. Woolridge used comparable and accepted DCF methods on different proxy groups and yielded widely varying results. Variabilities in the characteristics of the proxy group members, such as mix of utilities, percent of revenue from regulated activities, company size and business market, indicate that it is likely that the DCF model would produce substantially variable results based solely on the proxy group members selected. The apropos determination of earnings per share, based on the proxy group members selected, and the appropriate discount rate to use in the DCF model is subject to wide interpretation, rendering the results of DCF modeling presented by the witnesses of questionable application in this proceeding. In general, the most appropriate use of DCF modeling is to value the stock of large, publicly traded firms.

The Department takes the position that the CAPM technique is more well-suited as a predictor in this docket than the DCF modeling. However, since all predictive financial models contain some degree of error, the Department utilized the DCF results in its estimated average of the cost of capital.

iv. CAPM

The CAPM is based on the theory that the relevant risk of any asset is its relative contribution to the total variability of the market portfolio held by all investors. That is to say, investors are able to invest in a variety of portfolios of different risks and made up of various combinations of assets including a risk free asset. This risk free asset has no chance of default and so no default risk and has a guaranteed real rate of return. Under these parameters, a rational investor would only invest in market portfolios yielding a return comparable to a similar risky combination of a perfectly diversified market portfolio and the risk free asset. In this situation, an investor would only need to be compensated for a company's

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non-diversifiable risk since any other risk could be eliminated in a properly balanced portfolio. The formula for the CAPM is as follows:

$K = R_f + B (R_m - R_f)$
where: K = required return on equity
R_f = return required on the risk free asset
R_m = return on the perfectly diversified portfolio
B = common equity beta risk measure or the nondiversifiable risk relative to the perfectly diversified portfolio

The Department applied the CAPM to its comparable group using the standard formula of $K = R_f + B (R_m - R_f)$. The Department used the most up to date risk free rate using a 30-year Treasury bond showing a coupon rate of 3.74% as of April 21, 2009 (the last day of the evidentiary portion of the hearing in this docket) for the R_f value. The Department believes the CAPM calls for a long-term risk free rate, which would be the 30-year Treasury. The beta (B) variable from Value Line was used for each of the utilities in the comparable group taken from Value Line, which shows a simple average of 0.70%. This is shown in the following table:

Gas Utility	Beta
AGL Resources Inc.	0.75%
Atmos Energy Corporation	0.65%
Laclede Group, Inc.	0.65%
NICOR Inc.	0.70%
Northwest Natural Gas Company	0.60%
Piedmont Nat. Gas Co. Inc.	0.70%
South Jersey Industries Inc.	0.75%
Southwest Gas Corporation	0.75%
WGL Holdings, Inc.	0.75%
Mean	0.70%

Woolridge PFT, Exhibit JRW-11.3.

The risk premium is the (R_m-R_f) variable in the CAPM formula. For this variable, the Department used an average of forward looking returns found in the record. The Department used Dr. Makholm's calculation of an average of risk premiums of 10.13% [(9.82 + 10.43)/2] from the Wall Street investment services of First Call and Reuters. Makholm PFT, p. 42 and Exhibit JDM-14. Dr. Makholm's market risk premiums were developed using the formula $[[D_o *(1 + g) + g] - R_f]$ and as such is the $(R_m - R_f)$ variable. The Department used Dr. Makholm's $(R_m - R_f)$ since it is forward looking and makes use of projected data for the entire S&P 500, which is a good proxy for investor expectations. In the past, the Department has used historical risk premiums, which was considered in this instance. However, the current financial crisis makes determining the proper historical period to use problematic. The Department did not want to appear subjective in selecting a historical time period in developing a risk premium and as such used a forecasted risk premium as an input into the CAPM calculation. Given the turmoil in the financial markets, the Department finds a market risk premium that is forecasted rather than historical better reflects investor expectations. Using the formula $K = R_f + B (R_m - R_f)$, the Department calculated a CAPM of 10.83% [K = 3.74% + 0.70 (10.13%) = 10.83%].

The Department also considered OCC's CAPM calculation. The Department analyzed Dr. Woolridge's risk premiums and found two surveys, Duke University

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Chief Financial Officer (CFO) survey (CFO survey) and the 2009 Survey of Financial Forecasters published on February 13, 2009 from the Federal Reserve Bank of Philadelphia (Federal Reserve Survey), that reflect investor expectations. Woolridge PFT, p. 54. The CFO survey is a survey of CFOs that the Department believes reflects investor expectations and shows an 8.30% return on the market or R_m. The Department believes that the Federal Reserve Survey also reflects investor expectations since it is a survey of financial forecasters which shows a 6.50% return on the market R_m. The Department used this data from Dr. Woolridge in that they are both projected surveys, which the Department deems comparable to Dr. Makholm's projections in terms of use by investors and the analytical rigor used to develop them. The Department took the simple average of the CFO survey of 8.30% and the Federal Reserve Survey of 6.50%, which calculates to 7.40% [(8.30% + 6.50%)/2] expected return on the market which is the R_m variable. When using this 7.40% R_m variable in the formula (R_m - R_f), this calculates to a 3.66% (7.40% - 3.74%) risk premium, which is comparable to Dr. Makholm's 10.13% risk premium. The Department then applied the 3.66% risk premium in the CAPM formula using information in the record which calculates to 6.30% [3.74 + (.70 * 3.66%)].

The Company and OCC used the same basic methodologies for their CAPM calculation but differed in the equity risk premium determination. The Department believes in attempting to track forward looking investor expectations, it is necessary to use both the Company's and OCC's equity risk premiums. The Department used two studies from both the Company and OCC to be balanced and fair. These four studies represent Wall Street analysts, chief financial officers of corporations, and financial forecasters and as such the Department believes reflect investor expectations. Therefore, the Department takes a simple average of the CAPM using the Company proposed risk premium, 10.83%, and the CAPM using OCC risk premiums, 6.30%, for a CAPM investor expected ROE of 8.57% [(10.83% + 6.30%)/2].

v. Flotation Costs

The Department has not provided an adjustment for flotation costs given the particular circumstances of the instant case. Dr. Makholm's adjustment for flotation costs uses data from 1989, 1992, 1994, 1996, and 1997. The Department finds this data outdated and as such not reflective of the rate year. Makholm PFT, Exhibit JDM-12, p. 1. Southern is a wholly owned operating subsidiary of Energy East and has not issued equity on its own since 1996 and will not be issuing it in the future. The Department agrees with OCC's witness who stated, regarding flotation costs:

Dr. Makholm has not identified any such costs for Southern. Nonetheless, he still insists on adding 22 basis points (0.22%) to his DCF results for flotation costs. This means incremental annual revenues through a higher overall rate of return for unidentified expenses. There is no need for such an adjustment.

Woolridge PFT, p. 76.

The Department finds merit in OCC's argument that since market to book equity ratios for LDCs is in excess of 1.60, there should be no adjustment for flotation costs as there is no dilution to stockholder's equity. See, Woolridge PFT, pp. 76 and 77. The Department denies the 22 basis point adjustment for flotation costs by Southern.

6. Overall Rate of Return

On a test year basis, projected to the midpoint of the upcoming rate year, the Company requested an overall rate of return of 10.08% reflecting a ROE of 12.20%. Schedule D-1.0. The modeling employed by the Department in this proceeding produced a DCF value of 10.15% and CAPM value of 8.57%. This produces a range of 8.57% to 10.15%, with an average of 9.36%. The Department recognizes Southern's request of 12.2%. The Department takes note of the analysis of OCC, which includes a developed range of 7.0% to 9.6%, yielding an average of 8.3% and a recommended rate of 9.0%. The Department finds that 9.36% is a fair rate of ROE and is in the range of reasonableness developed by Dr. Woolridge of 7.00% and Dr. Makholm of 12.51%.

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This return is calculated for gas-regulated operations only, using the approved capital structure and capital costs, as follows:

Class of Capital	Amount	Percent of total	Cost	Weighted Cost
Short-term debt	$22,500,000	4.65%	2.48%	0.12%
Long-term Debt	$209,800,000	43.35%	7.19%	3.12%
Common Equity	$251,652,971	52.00%	9.36%	4.87%
Total Capitalization	$483,952,971	100.00%		8.10%

The Department finds that these rates, when applied to the rate base found reasonable for the Company, should produce operating income sufficient for Southern to operate successfully and serve its ratepayers, maintain its financial integrity, and compensate its investors for the risk assumed.

Based on the discussion in Section II.L. Maximum Daily Quantity, the Department reduces the ROE by 10 basis points for an allowed ROE of 9.26% and a weighted cost of capital of 8.05%. For purposes of its monthly earnings report to the Department, the Company shall use the capital structure allowed by this Decision.

S. EARNINGS REVIEW PERIOD

Southern asserted that Conn. Gen. Stat. § 16-19(g) states that a public utility is entitled to be compensated through a customer surcharge if the Department determines in a final rate Decision that follows a Conn. Gen. Stat. § 16-19(g) interim rate Decision that the rate decrease so ordered was either excessive or unwarranted. Southern concluded that the Department recognized the potential for implementing a surcharge in a subsequent proceeding in its Overearnings Decision. Specifically, that the Department ordered Southern to file as part of the rate case pro forma adjustments for a rate year beginning October 24, 2008. Southern calls this period the "Earnings Review Period" (ERP). Southern believes that its testimony and exhibits demonstrate that the monthly rate credit of $0.0621 per ccf should be terminated immediately. A compensatory rate surcharge should be implemented because the interim rate decrease ordered in the Overearnings Decision was unwarranted. Earnings Review Panel PFT, pp. 4 and 5.

Southern utilized the same basic methodology it employs in meeting the Standard Filing Requirements of a general Conn. Gen. Stat. § 16-19 rate proceeding. However, Southern modified this process to eliminate what it believes were unnecessary or redundant schedules. The test year for the ERP remains constant with the instant proceeding, which is the 12 months ended June 30, 2008. However, the ERP rate year estimates differ from the traditional pro forma rate year in two major areas. First, the period of time is different in that the ERP rate year is the 12 months ended October 23, 2009, which represents an overlap of the traditional pro forma rate year by approximately four months. Second, the ERP rate year is not normalized and annualized. Southern stated that although there is a timing overlap, it is very possible that estimates in the ERP year may be different for that particular month than that contained in the traditional rate year. Earnings Review Panel PFT, pp. 5 and 6.

Southern asserts that a surcharge is necessary because the Company's analysis demonstrates that the interim rate credit should not have been implemented due to the results of its ERP rate year forecast. This pro forma analysis demonstrates that the interim rates being collected by Southern pursuant to the Department's Interim Rate Order Decision (IROD) are less than the rates that should be approved by the Department for the ERP rate year. According to the Company, a surcharge must be implemented because the interim rate decrease has reduced its earnings to 400 basis points below the ROE

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level that Southern claims the Department found just and reasonable in the IROD. Additionally, the appropriate analysis under Conn. Gen. Stat. § 16-19(g) is to compare the ROE resulting from the interim rates reflecting the imposition of the rate credit and the ROE that would have been achieved under rates that should apply during the ERP. Reply Brief, pp. 7 and 8.

Southern proposed to calculate the surcharge based on the actual amount of revenues not collected as a result of the IROD. For the period August 5, 2008 through the end of 2008, Southern calculates that it has already reduced rates by approximately $3.8 million. Once the IROD rate credit ceases, Southern proposes to calculate the surcharge by dividing the actual revenues not collected by the pro forma ERP firm ccf excluding special contracts. Earnings Review Panel PFT, p. 14. Southern proposed to recover through a surcharge the difference between the IROD interim rates collected and the rates that would be finally approved by the Department for the ERP with a true-up to ensure that the surcharge does not exceed the amount of the IROD interim rate credit actually applied to customer bills. The Company seeks to recover through the surcharge what it would have been recovering through base rates since the inception of the IROD. In addition, Southern proposed to monitor the actual amount collected through the surcharge and would either charge or credit deferred gas costs at the end of the twelve-month surcharge period for the difference between actual surcharge collections and the dollar certain amount. Earnings Review Panel PFT, pp. 14 and 15.

The Department rejects the Company's fundamental argument that the appropriate analysis under Conn. Gen. Stat. § 16-19(g) is to compare the ROE resulting from the IROD interim rates reflecting the imposition of the rate credit and the ROE found appropriate in the final Decision herein. This construction would convert the surcharge provisions of § 16-19(g) into an ROE maintenance mechanism in contravention of traditional ratemaking principles. "An authorized rate of return is not a guarantee of any level of revenues or return."Connecticut Light & Power Co. v. Public Utilities Control Authority, 176 Conn. 191, 208 (1978)."A regulatory commission is powerless to 'guarantee' a specified rate of return."S. New Eng. Tel. Co. v. Dep't of Pub. Util. Control, 274 Conn. 119, 125 (2005).Conn. Gen. Stat. § 16-19(g) states, in pertinent part, that:

The department shall hold either a special public hearing or combine an investigation with an ongoing four-year review conducted in accordance with section 16-19a or with a general rate hearing conducted in accordance with subsection (a) of this section on the need for an interim rate decrease . . . At the completion of the proceeding, the department may order an interim rate decrease if it finds that such return on equity or rates exceeds a reasonable rate of return or is more than just, reasonable and adequate as determined by the department. Any such interim rate decrease shall be subject to a customer surcharge if the interim rates collected by the company are less than the rates finally approved by the department or fixed at the conclusion of any appeal taken as a result of any finding by the department. Such surcharge shall be assessed against customers in such amounts and by such procedure as ordered by the department.

Nothing in Conn. Gen. Stat. § 16-19(g) requires the "rates finally approved by the department" to consist of one for the ERP period and another for the rate year. This construction is supported by the language of the statute, by case law, and by reading the interim rate decrease statute *in pari materia* with the interim rate increase statute.

The Connecticut Supreme Court acknowledged that an interim rate decrease is essentially the front end of a rate case. Specifically, the court held that it:

. . . cannot ignore the statutory scheme to which an interim rate decrease is, as the term suggests, temporary. An interim rate decrease hearing is to be followed by a full rate case determination hearing. The fact that an interim rate hearing results in only temporary ratemaking until more information is available at a subsequent full rate case indicates that the legislature vested the department with the discretion to determine whether an interim rate adjustment was necessary at all.

Office of Consumer Counsel v. DPUC, 252 Conn. 115, 124 (2000).

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Finally, this conclusion is further supported by the construction of the interim rate increase section Conn. Gen. Stat. § 16-19(d). The relevant provisions of the interim rate decrease and interim rate increase sections share significant language, and are analogs of each other. [FN8]Conn. Gen. Stat. § 16-19(d) states, in pertinent part, that:

> FN8. Upon introducing Substitute for House Bill 7216, "An Act Permitting the Department of Public Utility Control to Order Interim Rate Decreases," Senator Gary Hale explicitly linked the interim rate decrease and interim rate increase sections together:
> The first time in Connecticut's history that this bill is passed and signed by the governor, the Department of Public Utilities Control [sic] will be authorized to grant a utility rate decrease without a full hearing under special circumstances. For a number of years if a utility company has earned less than its authorized return on equity, those companies can [petition the Department for] an expedited process [for] an interim rate increase.
> 30 S. Proc., Pt. 11, 1987 Sess., pp. 4040-4041.

Nothing in this section shall be construed to prevent the department from approving an interim rate increase, if the department finds that such an interim rate increase is necessary to prevent substantial and material deterioration of the financial condition of a public service company, to prevent substantial deterioration of the adequacy and reliability of service to its customers or to conform to the applicable principles and guidelines set forth in section 16-19e, provided the department shall first hold a special public hearing on the need for such interim rate increase . . . The department shall order a refund in an amount equal to the excess, if any, of the amount collected pursuant to the interim rates over the amount which would have been collected pursuant to the rates finally approved by the department in accordance with subsection (a) of this section or fixed at the conclusion of any appeal taken as a result of any finding by the department. Such refund ordered by the department shall be paid by the company to its customers in such amounts and by such procedure as ordered by the department.

The parallels between the interim rate decrease and increase statutes are unmistakable. Both statutes allow a temporary, emphasize interim, rate amendment at the conclusion of a special public hearing. Both statutes require a refund based upon a comparison of the interim rate to the rates, emphasize finally, approved. Both statutes use identical language to grant latitude to the Department in the determination and return of any under- or over-collection, as the case may be. The Department's decision to apply the two sections consistently is therefore both natural and legally supportable. [FN9]Nothing in the interim rate increase section requires the Department to guarantee a specific ROE, nor to construct a distinct revenue requirement for an ERP, as the Company insists must be done for the interim rate decrease. On the contrary, the interim rate increase section specifically requires the Department to compare the rates collected on an interim basis to the amounts which would have been collected pursuant to the rates finally approved. The Department will conduct the same comparison to implement the interim rate decrease statute.

> FN9. Statutes should be read so as to harmonize with each other, and not to conflict with each other. Stern v. Allied Van Lines, Inc., 246 Conn. 170, 179 (1998). Related statutory provisions in pari materia often provide guidance in determining the meaning of a particular word or phrase. Skakel v. Benedict, 54 Conn. App. 663, 676 (1999).

While Conn. Gen. Stat. § 16-19(d) requires a public service company to refund any excess interim rate increase along with interest, the Department will not apply interest to the surcharge. The Department believes that reasons exist to treat §§ 16-19(d) and 16-19(g) differently in this regard. The specific statutory requirement to refund any excess interim rate increase collected stands as a discouragement to public service companies seeking, on their own volition, to impose an interim increase before the public service commission has had the opportunity to set just and reasonable rates after a full rate case. The Department should not, however read any such discouragement into the General Assembly's requirement that the Department reduce rates provided

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any of the § 16-19(g) conditions are satisfied.

In the IROD, the Department determined that an interim revenue reduction of $15,101,958 was warranted. This revenue reduction was implemented through a volumetric interim rate credit of $0.0621 per ccf, which was determined by dividing $15,101,958 by the approved sales throughput from Southern's last rate case (243,371,820 ccf). In the instant proceeding, the Department approves a final revenue reduction of $12,461,265 and a firm sales forecast of 270,793,470 ccf. This results in an overall firm rate reduction of $0.0460 per ccf ($12,461,265 / 270,793,470). Consequently, the "rates finally approved," as compared on a per ccf basis to the interim rates, are $0.0161 ($0.0621 - $0.0460).higher and the Company is entitled to a debit surcharge of $0.0161 per ccf

The surcharge will commence on October 1, 2009 unless an appeal has been taken. If an appeal is taken, the surcharge will be held in abeyance until the conclusion of judicial review or the Company's affirmation that no appeal or further appeals will be taken. The surcharge will remain in place until the Department, through monthly review, determines that the surcharge target revenue has been obtained. Surcharge target revenues are defined as the actual sales that the $0.0621 interim rate was applied to multiplied by the surcharge of $0.0161 per ccf. Since the existing interim rate credit will continue through August 19, 2009, the Company will not know actual interim rate sales until after the effective date of this Decision. The Company will be directed to file this information by September 11, 2009. Monthly reports tallying new surcharge revenues will commence November 16, 2009, unless an appeal is taken.

Southern claims in their Written Exceptions that in the IROD, the Department "expressly ordered" a particular method of determining the amount of the surcharge and that the instant Decision reverses that approach. Written Exceptions, pp. 1, 5. The Department finds no support for the Company's claims in the IROD. The IROD directs the Company to provide information with which it will make a Decision. It does not state that the information provided would constitute the only information on which the Department could rely. The Company's interpretation of the IROD suggests that not all the information in the current record can form the basis for making a final decision in this matter. The Department used the entire record in this proceeding to form the basis for its Decision and declines to rely on only selected parts of the record to form its conclusions.

The Company claims that the methodology adopted by the Department to calculate the surcharge constitutes retroactive ratemaking and their approach is not. See e.g., Written Exceptions, p. 7. But see, Office of Consumer Counsel v. DPUC, 252 Conn. 115, 124, 2000 (The most recent case on the subject that the Company fails to cite preferring to cite a older lower court opinion; CL&P, 40 Conn. Supp. 520.) The OCC, 252 Conn. 115, 124 defines the Conn. Gen. Stat. § 16-19(g) statutory scheme as "temporary". The Department believes that Southern's preferred approach to interpreting Conn. Gen Stat. § 16-19(g) is the most troublesome form of retroactive ratemaking because it picks and chooses which parts of the historic data, they call actual data, and comingles it with prospective and forecast data. The Department's approach uses only prospective data.

The Department notes that the 5.74% ROE the Company quotes in its Written Exceptions (See e.g., pp. 5, 8) is not merely a function of the IROD but includes the expenses that the Company chose to incur during that period. Had the Company chosen to spend more money in that period, its ROE for that period would be correspondingly lower. The Department is not persuaded that the ROE reportedly earned by Southern during the period reflects solely the effect of the IROD.

Southern takes issue with the Department's failure to apply interest in calculating the surcharge. The Department cites OCC, 252 Conn. 115 where the Court left to the Department's discretion how the surcharge should be applied.

T. CURRENT ECONOMIC CONDITIONS

As part of its rate increase request, the Company originally proposed an $11,352,258 increase to its operating

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expenses. RRP PFT, p 14. In its Application, the Company claims that it has "aggressively managed its expenses, cash flows, collection efforts and investment activities" and, as a result, the proposed rate increase "reflects current economic conditions." Application, pp. 1 and 2. The Company proposed $30,085,249 for the rate year total uncollectible expenses, both non-hardship and hardship. Response to Interrogatory GA-2, Corrected Attachment 2, pp. 27 and 29; Schedules C-3.8 and C-3.17. The Company forecasted and proposed dividend payout of $17,500,000, $31,500,000, and $31,500,000 during calendar years 2009, 2010 and 2011, respectively. Response to Interrogatory GA-321. Without further comment, the Company attached Schedule B to its Application showing the impact of the proposed rates on its residential customers' gas bills. For example, a customer working all year at a full-time minimum wage job would pay approximately 31.6% of his/her gross income for gas service or over $5,100 per year. [FN10]The Company presented these numbers as part of its demonstration to the Department that it needs higher rates.

> FN10. 40 hours x 52 weeks x $8.00 hour = $16,640. 150% of the 2009 Federal Poverty Guidelines poverty level-household of 1 is $16,245. Assuming 200 Ccf of consumption under rate RSH and $16,245 annual gross income 31.6% = $5,133.

Customers contacting the Department regarding rates and this rate case objected to high rates. Approximately 13,000 customers, or approximately 8% of the residential class, had their service terminated in 2008 not counting terminations in December 2008. RRP PFT, p. 16; Schedule E-3.7, p. 37. These startling numbers and others discussed herein demonstrate to the Department that the Company has failed to aggressively manage its rate year expectations, expenses, cash flows, collection efforts and investment activities. The Company rate increase request does not reflect current economic conditions.

References to the "recent economy" and the "current economic situation" litter the record. Citations Omitted. Apparently, what does not appear in the record is how the Company, its shareholders and labor force have shared the experiences of many of Connecticut's citizens. There were no Company proposals to reduce wages, increase unpaid time off, make staff reductions or reduce dividends. The Company did propose staff increases, wage increases, staff bonuses and increasing dividends. The Company eventually withdrew its initial request for executive incentive compensation. The Company also proposed net growth in capital investment; therefore, increasing overall rate base. When a gas customer must pay such a large proportion of all their income to keep warm and cook, it is not surprising that they cannot afford to pay their bills.

As discussed in this Decision, the Company's deficient application of The Uniform System of Accounts, aggressive ratebase addition requests, unprecedented rate case expense request and historically dismal (though recently improving) uncollectible balances and collection practices do not suggest to the Department that the Company is at all mindful of the costs it imposes on Connecticut. The Department finds it nearly incomprehensible that substantial MDQ and demand charges and revenue misallocations continued for several years undetected. As a result, revenues were initially unrecovered and borne by shareholders. Subsequently, the revenues were recovered from other ratepayers. The Department recalls the prolonged and unsuccessful Company efforts to install mandated DDMS. In addition, the Company provided the Department what could reasonably be considered a generic cost of capital analysis suggesting a return to a regulated Company many times greater than what an average person is likely to expect on their personal or retirement savings accounts. The Department will direct the Company to prepare and present a plan to manage its operational expenses and capital investments that genuinely reflect current economic conditions and which addresses the other issues listed above. The Department, State of Connecticut and the Company's ratepayers simply cannot maintain this as the status quo operation of the Company.

U. COMPANY'S BURDEN OF PROOF

In Southern's Written Exceptions at page 67, the Company stated that "[i]t is inconceivable that SCG should

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be required to anticipate this level of scrutiny ... describing the minutiae of each individual asset that is proposed ...."One of the items that the Company describes as minutiae is $505,000 it proposed for Information Technology, which the Department disallowed in the draft Decision. What is inconceivable is the Company's disregard of Conn. Gen. Stat. §§ 16-11 and 16-22. These statutes require that the Department be kept fully informed of all manner of operation of all regulated companies and that the burden of proving Southern's case falls squarely on Southern.

III. FINDINGS OF FACT

1. Southern mailed a Notice pursuant to Conn. Gen. Stat. § 16-19a advising customers that the Company had filed an Application on January 20, 2009 to increase its rates.
2. The Department received 22 letters and emails regarding the Company's Application unanimous in their opposition to the proposed rate increase.
3. Separating commercial from industrial customers in the UPC and customer models will result in more accurate forecasts.
4. The Department rejects the two-part price variable model.
5. The Department has no practical way of conducting its own investigations and what-if adjustments to the models.
6. The sales forecast developed in Late Filed Exhibit No. 59 and submitted in Response to Interrogatory GA-2 Supplement No. 2, is reasonable and approved with one caveat.
7. The Department approved sales forecast changes the Company's proposed rate sales forecast.
8. The Department approved sales forecast will result in total revenues of $388,663,339, an increase of $4,261,093 from the Company's Final Proposed Forecast and a limited number of cascading changes to certain expense and rate base accounts.
9. The Company chose to use older data in its Application when more recent and relevant data was available and when given the opportunity to do so in its sales forecast updates, it chose not to.
10. In the future, the most current data available should be used when normalizing sales.
11. In the response to Interrogatory GA-98, 23 of the 277 retirements listed appear to be expenses.
12. Southern's accounting demands further investiga- tion.
13. The Department was unable to verify whether assets in Account 378 are proper.
14. Southern provided conflicting testimony regarding the RFPs and bidding process for the HVAC systems.
15. Southern did not receive three HVAC RFPs as is its policy.
16. The purchase of the second emergency generator for the Orange Operation center is redundant and unnecessary.
17. The Company did not indicate during the hearings, why it needed a second emergency generator at the Operations Center.
18. The addition of $450,000 related to the proposed pipe yard and workplace construction is unnecessary at this time
19. The Company could not determine which of the proposed retirements related to Account 391 resulted from a book retirement versus physical retirement and disposal of the asset.
20. A significant number of retired assets should never have been included in rate base.
21. Southern cannot verify whether any of the retired assets related to Account 391.1, including paintings, remain in the Company's possession.
22. The Company was unable to provide documentation regarding specific items remaining in rate base.
23. The Department is unable to verify whether the remaining assets included in the rate year rate base of $1,719,589 are properly included in Account 391.1.
24. It is reasonable to assume that additional rate base accounts would have the same issue as those in Account 391.1.
25. The inclusion of expense related entries in the list of retirements for Account 391.1 is an indication of accounting deficiencies discovered in other plant accounts discussed in this Decision.
26. The reclassification of the assets occurred five months prior to the addition of EEMC's software license in rate base.
27. The Department calculated that 17.6% of the test

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year rate base was attributed to the EEMC License Fee by dividing the $200,000 fee by the total test year rate base of $1,136,016 for Account 391.2.
28. Southern should not have included any cost in any rate base account related to its affiliate.
29. Including any item in rate base related to an affiliate of Southern is unacceptable and highly improper.
30. Seventeen items, all described as 2008 GMC Full Size 4x2-1 Ton Van with a cost of $1,165, directly correspond to the other seventeen items with the same description with a cost of $23,312.
31. The Department believes that the items included in Account 392 described as Ford Sedans and Rangers are not vehicles and should not be included in this account because the prices of the account entries are between $504 and $1,833 and too low to be vehicle costs.
32. The list of capital additions did not include any reasonable prices for Ford Sedans or Rangers.
33. It appears that the account entries in Account 392 are expense related items and should be expensed and not included in rate base.
34. The Department is unable to verify whether the individual entries included in proposed rate year rate base correspond to the Uniform System of Accounts.
35. The retirements of construction related vehicles from Account 392 are an indication of accounting deficiencies in rate base accounts, similar to the other plant accounts discussed in this Decision.
36. Assets in rate base are comingled with assets that belong in other accounts along with improperly included expense items.
37. The Department will not accept the Company's proposed adjustment and transfer of the $1,090,733 from Account 392 to 396.
38. Southern is retiring assets under Account 392 based on the age of the equipment.
39. The Department cannot verify whether the items retired under Account 392 are valid.
40. Southern's general fleet policy regarding retiring assets because of their age is inadequate.
41. The Company did not compare the costs associated with maintaining the equipment versus the cost associated with purchasing new equipment.
42. It appears that Southern is unnecessarily increasing rate base by purchasing assets that are unnecessary.
43. Age is only one factor that should be taken into account when an item in rate base is retired.
44. Retiring assets to take advantage of accelerated depreciation or because of the asset's age is usually not cost effective.
45. The correct analysis that Southern should perform is a comparison of the cost associated with maintaining a specific piece of equipment versus the costs associated with purchasing new equipment.
46. Since the Company did not compare the costs of maintaining current equipment assets to the costs associated with purchasing new assets, it is unclear which assets should be retired or retained in the Company's fleet.
47. The Department will assume that 50% of the capital additions are appropriate and included in the rate year rate base.
48. The 50% reduction to the rate year rate base sufficiently accounts for any disallowance properly related to the Ford Sedan and Rangers stated above.
49. The Department will apply the 6.87% depreciation rate from Account 396 to all assets included in Account 392.
50. Applying the current depreciation rate for Account 396 to Account 392 prior to the transfer of assets is a simple methodology.
51. The proposed depreciation rate of 26.10% for Account 396 is significantly overstated.
52. Since including construction vehicles in Account 392 and not in Account 396, the Company has skewed the average service lives, thereby, skewing the depreciation rate for this account.
53. Since the Company must take responsibility for its accounting practices, the Department finds the proposed depreciation rate invalid.
54. The Department was unable to determine whether the capital additions to Account 397 were actually purchased.
55. Numerous assets were included in the wrong Uniform System of Account's, accounts.
56. Numerous accounts included expense related items that were retired from rate base accounts.
57. The accounting and depreciation related issues that arose from the inclusion of assets and expenses related items in wrong accounts need to be corrected.

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58. The proposed revenue requirement for the rate year includes expenditures for work to be performed at district regulator stations.
59. Using $169,000 for capital expenditures is reasonable because of the current economic conditions.
60. The addition of the Meter Relocation Program, at best, could move an additional 300 services during the rate year with capital costs of $2 million; therefore, it continues to be reasonable to assume that it will take 50 years to move all 53,504 inside meters outside.
61. The Company should have the same accessibility to inside meters to either install remote shut-off devices or shut-off service when an account is delinquent.
62. Public Act 09-31 enhances the Company's ability to gain access to shut-off delinquent accounts.
63. The Company can make a landlord responsible for their tenant's delinquent gas bill if the landlord denies access to inside meters for shut-off.
64. Public Act 09-31 reduces the need to relocate meters outside for credit and collection issues.
65. The Department reviewed the table included in the OCC's brief and compared it to Southern's response to Interrogatory OCC-187, Attachment1.
66. The Department's analysis included in Section II.C.2.e. New Business reduced the Company's proposed capital expenditures for the rate year related to Normal New Business by 40%.
67. New business is directly related to meter and regulator installations via the addition of new service installations that require a new meter.
68. It is appropriate for the Department to carry the 40% reduction over to meter service, regulators and installations specifically related to the New Business portion of this category of capital expenditures.
69. The inclusion of the HVAC work, Pipe Yard construction, replacement of the emergency generator and the workplace construction items in the rate year capital expenditures inappropriately assumes that the Company is spending the same amount on these projects annually as long as the rates are in effect.
70. The downturn in construction experienced toward the end of 2008 and projected for 2009 was not similar to anything experienced between 2004 and 2008.
71. Given the current and projected rate-year economic environment, housing and business starts can be expected to be at an all time low, not the average of five years with economically dissimilar characteristics.
72. The Company's emphasis on energy conversions is nothing new.
73. New business and conversion markets have been aggressively pursued since the earliest days of the natural gas industry.
74. To redirect marketing dollars alone does not guaranteed sales success in a market where relative energy prices are established on the world stage and customers need to make a substantial investment in new equipment even after financial incentives.
75. The Company failed to establish a reliable numerical relationship between the addition of new customers and the level of plant investment.
76. Arguing that sales flow from an investment allowance is both illogical in a rate case environment and impractical in practice.
77. Service Transfers are directly related to and an integral part of the Bare Steel and Cast Iron Replacement Program.
78. Service Transfers are a capital replacement program that is intended to remove and replace specific types of mains and service connections and has been in effect for a number of years.
79. Service connections must be relocated to a new main so that the old main can be retired.
80. Work performed on Service Transfers is not related to maintenance of the existing service, but is directly related to the capital program for main replacements.
81. The Department used the actual data from 2006-2008 in the table above to verify the validity of the proposed expenditure of $967,000 for the rate year.
82. The Department compared the largest historical expenditure associated with Service Transfers of $420,922 to the total dollars spent on the Bare Steel and Meter Relocation programs of $9.5 million during 2008.
83. The Department calculated the capitalized Service Transfer Charges versus Bare Steel and Meter Relocation percentage of 8.80% [$967,000 / ($8 million + $1.5 million + $1.5 million)] for the proposed rate year using the above cited calculation.
84. The proposed rate year Service Transfer expenditure is twice as much as the historical data.
85. The Department congratulates Southern on its abil-

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ity to install AMR devices on almost 100% of its customers' inside and outside meters.
86. The Department cannot determine whether information technology software / hardware, telephone equipment, and other capital office equipment are already in place or need to be installed.
87. The Department was unable to determine whether tool, shop, garage and safety equipment are already in place or need to be purchased.
88. The forecasted net hardship write-off for the calculation of the deferred balance to be amortized and the estimated annual hardship ongoing recovery amount were overstated.
89. The Company did not update its forecast or revise the deferred balance to reflect updated figures.
90. The forecasted additional write-offs included in the deferred balances should not be extrapolated to include any amount in the rate year.
91. Expenses forecasted should be for periods subsequent to the test year, and for which data is not available, and prior to the start of the rate year, for which the pro forma ongoing recovery amount is being requested.
92. To determine the deferred balance at the midpoint of the rate year, only half of the amortization expense should be deducted from total beginning deferred balance, or simply calculate the average of the beginning and ending balances.
93. The Company's deferred hardship balance as of midpoint of the rate year in rate base was overstated by $7,296,680 and the Department rejects the Company's position that its overstatement was only $2.2 million.
94. To accept the Company's calculation because it is in concert with past practices is not a good rate-making policy.
95. Past practices may help establish consistency but they are not regulatory binding nor are they precedent setting.
96. Accepting overstated deferred expenses calculations simply because the methodology the Company employs is consistent with past practices would not be balancing the interest of the ratepayers with that of the investors.
97. The Department calculated the deferred MPP balance of $7,836,696 as of December 31, 2009.
98. Deferred MPP expenses should not be forecasted to the midpoint of the rate year.
99. The Company's assertion that the NBV of these properties were previously in rate base is not a prima facie reason for them to be reinstated.
100. Southern had ample opportunities to discuss the difficulty it was having selling the MGP sites with the Department.
101. The Company acknowledges that the MGP sites will not be used for utility operations.
102. Ratepayers currently pay O&M and environmental remediation expenses that are significantly in excess of the rental income for these properties.
103. The Sarbanes-Oxley Act of 2002 created the Public Company Accounting Oversight Board (PCAOB), a private nonprofit corporation charged with overseeing the auditors of public companies whose goals are to protect the public and investors' interest by promoting informative, fair and independent audit reports.
104. The Department disagrees with the Company's proposal to amortize ADITs related to these TBBS adjustments.
105. The Company failed to adequately explain how Section 103 specifically affected its treatment of the ADITs for the unidentified items or that ADITs should be expensed for rate-making purposes.
106. Southern failed to indentify which PCAOB's standard specifically emphasized the attestation of ADITS and
107. The Department treats ADITs, identified and unidentified, as offsets to rate base items for which recoveries or recognition has being temporarily deferred.
108. The mere fact that the Company's affiliate tracks and attests to the existence of the differences between book balances and unidentified accumulated deferred income tax balances is not a justification for the proposed amortization.
109. The Department assumes that the Company tracks and attests to the existence of all other ADITs, identified and unidentified, and underlying regulatory deferred assets or liabilities.
110. The Department does not believe it is proper or in the public interest to charge currently non-incurred and non-regulatory expenses to ratepayers and then subsequently credit back the same charges to them because ADITs, credits or charges, are not regulatory items subject to amortization.

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111. The adjudication of similar matters that were raised and litigated is reviewed in the context of each individual proceeding.
112. Southern's ratepayers should not have to pay for an expense because a similar adjustment was not addressed in CNG's case.
113. It is a customary regulatory practice to allow an adjustment to rate base in recognition of the timing difference between when revenues are received and when expenses are paid out.
114. For larger utilities, the Department typically prefers that a lead/lag study be conducted to determine the appropriate cash working capital allowance rather than using some rule of thumb approach or the utility's balance sheet result.
115. Deferred taxes and amortizations expenses reduce rate base as they occur, which deprives the Company of a return on investment while it waits to recover the expense through rates.
116. The return on equity used to calculate the balance is determined from market data assuming an annual return with a quarterly dividend requirement and the timing by which the income is needed for the Company to be made whole relative to this element, making this category appropriate for inclusion in the lead/lag study.
117. The Company's use of the sum of the daily accounts receivable balances in calculating the collection lag, this method of calculation has implications on how uncollectible expense should be treated in the lead/lag study.
118. Accounts that are ultimately written-off as uncollectable are part of the accounts receivable balance until they are written off.
119. Removing uncollectible expense from the lead/lag study arbitrarily assigns the expense a lead of 92.23 days.
120. It is more appropriate to include prepayments; notably, insurance and property taxes in the lead/lag study and remove them as prepayments in the rate base because the lead/lag study directly measures the net lag and daily expense associated these items and assigns them rate base treatment based on that net lag and daily expense level.
121. Comparing the results of first quarter 2008 with first quarter 2009, appropriately takes into consideration this seasonality and indicates an updated revenue lag that is 2.5 days less than the test year results would indicate.
122. Shortening the charge-off period from six months to three months is appropriate and consistent with the Company's more aggressive approach to collections.
123. Accelerating the charge off period provides for accounts receivable balances that are more in line with what those balances are actually worth (i.e., collectible).
124. Changing from a six-month charge-off policy to a three-month charge-off policy has two largely offsetting impacts on working capital.
125. The one-time write-off has ratemaking implications.
126. The uncollectible expense as used for ratemaking is a prospective expense intended to represent the amount of current revenues that will ultimately prove uncollectible.
127. There is no ratemaking provision whereby uncollectible write-offs are compared with pro forma uncollectible expense and trued-up in future ratemaking proceedings.
128. Neither the length of time "uncollectibles" are held as receivables nor the amount of write-offs taken or not taken at any given point in time impacts the amount ultimately proving to be uncollectible.
129. Unlike other revenues, service lag revenues are trued-up and recovered through the PGA.
130. The PGA effectively aligns meter reads with service rendered and eliminates the service lag.
131. The Company's logic is flawed because it assumes in its arguments that the billing cycle and service period are one and the same.
132. To align the purchased gas cost related revenues collected through the PGA with the service period purchased gas costs incurred by the Company, an amount of time equivalent to the service lag must be subtracted from the normally calculated revenue lag.
133. The lead/lag study result was based on the measured timing of payments from Southern to affiliates for service rendered; therefore, contractual obligations between Southern and its affiliates better represents the cash working capital requirements associated with this expense category.
134. For transactions between affiliated entities, where

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incentives to best manage a company's cash flow is diminished, contractual obligations often provide a better measure of working capital needs than past practice.
135. To determine the appropriate amount of lead days to use for uncollectible expense, the Department reviewed the amount of time receivables, that are eventually written off as uncollectible, remain in the receivable balance.
136. Hardship accounts and inside meter accounts which are hard to close due to legal protections and access difficulties, makes uncollectible expense associated with these accounts likely to have been in the receivables balance much longer than 180 days.
137. As with any expense, the Company incurs uncollectible expense when it renders service.
138. The purpose of a cash working capital study is to determine when cash reimbursement for that expense is needed by the Company.
139. The Department does not find a compelling reason to change the self-insured portion of the injuries and damages expense from a funded reserve expense to a pay-as-you-go expense.
140. The reserve approach causes an increase to working capital; but created reserve also serves as an offset to rate base.
141. The Department made adjustments to the amount of expenses or income allowed for ratemaking purposes.
142. The Department adjusted the expense and income levels used to calculate the cash working capital needs of the Company to mirror the expense and income levels allowed by this Decision.
143. In addition to the noted specific adjustments to rate base discussed in this Decision, the revenue requirements model used by the Department further adjusts rate base for the impacts of specific adjustments on deferred taxes and accumulated depreciation.
144. The Department's disallowance of the Company's proposed expansion of daily demand meters (DDM) to Rate RMDS residential customers reduces pro forma revenue at present rates by $27,518.
145. Several of the proposed deferred balances are not supported by the record in this proceeding.
146. The Department intends to halt the practice of deferring Department docket expenses between rate cases.
147. Docket expenses are generally nonmaterial, recurring expenses where deferrals should not be used.
148. Deferrals can lead to unintended consequences.
149. The Department thoroughly reviewed and analyzed the Company's proposed hardship expense for the rate year.
150. The forecasted net hardship write-off for the calculation of the deferred balance and the estimated annual hardship ongoing recovery amount were overstated.
151. The Company failed to update its proposed hardship forecast.
152. The average of 2004 through 2007 net hardship write-offs does not correctly reflect the outcome of efforts the Company had made to reduce its hardship write-offs since 2005.
153. To deliberately neglect the impact of the declines in both hardship A/R and the net write-off in 2008 is not balancing the needs of the Company with the interest of the ratepayers.
154. The five-year average, which includes the 2008's net write-off amount, to calculate the deferred forecast for three months April 1, 2009 through June 30, 2009 is appropriate and reasonable.
155. The Company's aggressive efforts are having positive impacts on the hardship write-offs.
156. The Department expects the net hardship write-offs for the rate year to be less than the 2008 level.
157. Allowing a hardship expense above the allowed amount will put an undue burden on ratepayers.
158. The forecasted MPP grants added to the deferred balance for amortization and the estimated annual MPP amount were overstated.
159. The Company should not be forecasting or extrapolating expense amounts into the rate year while at the same time estimating additional annual expense to be recovered in the rate year and beyond.
160. It is the deduction of the half-year amortization expense from the beginning deferred balance that brings the deferred balance to the midpoint of the rate year level
161. The MPP charges of $4,514,429 for 2008, is a better proxy for the pro forma annual MPP amortization for the current energy assistance grants.
162. OCC's recommendation to continue to allow $5,004,889 as the annual amortization expense for prior deferred balance puzzling giving its calculation that the

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unamortized balance of the deferred MPP as of July 1, 2009 is $11,153,976.
163. It is in the public interest to continue to apply the current high amortization level given the deferred balance amount at the beginning of the rate year and the current economic crisis.
164. It is not appropriate to ignore the results of the filed Depreciation Study.
165. It is appropriate to use the Depreciation Study with modifications.
166. It is premature to reduce the ASL from the prior Depreciation Study given the relatively young life of the account (oldest vintages less than 45 years old), lack of retirements (roughly 3% of historical additions) and concerns with some of the data used in the study for this account.
167. Given the lack of data and the concerns with the data, there is insufficient indication since the prior study to justify changing the ASL on Account 376.20.
168. Due to retirements, government's cost cutting and furloughs the Department assessment costs should be lower.
169. The Department typically allows utilities to apply a general inflation factor to O&M expenses not specifically adjusted elsewhere.
170. Without an inflation adjustment, the Company would not be made whole for increases in its O&M expenses not adjusted for elsewhere.
171. The Department adjusted O&M expense base of $6,844,674 produces an allowed inflation expense for the Company of $238,489 (3.4843% x $6,844,674).
172. The Company did not adjust the credit card bank fees deferred balance in rate base despite the revisions to both the accrued and forecasted deferred amounts in its updated filing.
173. The Company did not provide sufficient evidence to support the higher bank fees or larger customer usage of Kubra services to justify increasing charges beyond that related to the monthly average of 12,000 transactions.
174. The most recent 12 months ending March 31, 2009 actual Kubra transaction and credit card bank fee charges are more appropriate proxies for determining the rate year expenses.
175. The Company should not be forecasting deferred expenses to the midpoint of the rate year while simultaneously also proposing an additional recovery of an ongoing expenditure for the 12 months in the rate year.
176. The cost of KUBRA and related bank fees are ratepayer responsibilities.
177. The test year self-insured claim amount was significantly less that the pro forma five-year average because there was a refund from the insurance company regarding a claim that the Southern paid over and above the self-insured retention.
178. The Department excludes extraordinary or non-recurring items in its calculation of prospective expenses for the rate year and beyond.
179. A better guide for determining future expenses is using actual historical expenses paid over a recent period of time.
180. The reserve accounts contain accrued estimates of potential obligations.
181. Ratepayers should not be paying for funds set aside in reserve accounts.
182. The Department rejects the Company's revised 2.74% uncollectible rate for the rate year because it does not adequately reflect Southern's non-hardship expenditures since the 2005 Decision.
183. The Company's calculation is misleading and does not account for the noticeable decreases in non-hardship A/R and expenses since the 2005 Decision.
184. Somewhat disconcerting is the fact that the Company estimated non-hardship gross write-off amounts of $14,234,400 and $12,994,078 in 2007 and 2008, respectively, when the related non-hardship receivables were $21,576,180 and $20,135,179, respectively.
185. As the non-hardship A/R continues to decline from the high 2005 level, the Company's forecasts of gross write-offs of non-hardship residential customer accounts were increasing.
186. The Company's calculation of the proposed 2.74% bad debt rate and the use of write-off amounts for its calculation in the instant case are unreliable.
187. Using the typical three, four or five year average to calculate the rate year's bad debt rate ignores the clear downward trends in non-hardship receivables and expense and the steep declines in natural gas prices.
188. Using the averages of percentages of non-hardship write-offs or of expenses to calculate the bad debt rate

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and expenses ignores recent data.
189. Collection efforts are already having a positive effects on non-hardship portion of the uncollectible expenses.
190. The additional collection expenditures being approved in the instant case would further help improve collection results.
191. Prior period uncollectible rates are significantly higher because the Company's calculations include embedded natural gas commodity costs that are higher than those projected for the rate year.
192. The 1.9856% bad debt expense rate in 2008 better represents uncollectible rate for the rate year.
193. Currently, commodity gas costs are at historical lows.
194. The Department thoroughly reviewed the Company's testimonies and exhibits in support of the proposed non-hardship expenses for the rate year.
195. A review of the Company's aging A/R report indicated that non-hardship receivables had declined noticeable since the 2005 Decision.
196. The claim that the increases in the numbers of disconnected accounts are related to non-hardship A/R or expenses is unpersuasive.
197. The non-hardship A/R and expenses declined significantly from their 2005 levels.
198. The correlation between the number of disconnected accounts and the amounts of non-hardship account A/R and expenses is not clear.
199. The change from six months to three months to write-off delinquent final accounts does not create a one time charge.
200. An earlier write-off of any portion of hardship or non-hardship improves collection cycles as delinquent final A/R enter the collection process sooner; but, such change does not create any charge to income statement for the estimated amounts that should have been written off in past if the new three months write-off had been in place.
201. The Company did not explain how a one-time charge to the income statement would affect its other financial statements.
202. An affiliate's approach to estimating uncollectible write-off is neither GAAP nor mandated regulatory standard.
203. The change to three months for writing off final A/R should be done prospectively and would be reflected in A/R balances and net write-off amounts subsequent to the beginning of the rate year.
204. Varolli actual billings for the five months ending February 2009 does not show a monthly average billing of $20,000.
205. The capitalization ratios in Response to Interrogatory GA-375 are erroneous.
206. The Company failed to adequately explain the noticeable declines in the overtime expense factors from 2004 to 2008.
207. The overtime payroll expense factor had declined to 68.1% in 2008.
208. It is doubtful the Company will fill positions during the rate year given the uncertainty of the current economic climate.
209. The Company has not adequately measured and failed to validate the criticality of any open positions.
210. The process to recruit a training analyst itself is not a justification for including the positions cost in pro forma payroll expense.
211. The Company did not justify increasing employee levels above the test year count of 319.
212. The Company's proposal to calculate a ratio of overtime hours by comparing an average of three calendar years overtime hours to test year overtime hours is distortive.
213. Comparing pro forma overtime hours, determined as an average of calendar year data to fiscal test year levels ignores seasonality.
214. The ratio calculated in the Company's response, although based on overtime payroll expenses instead of hours, compares an average based on the same 12 months periods as the fiscal test year ending June 30, 2008, thus incorporating the known seasonality effect.
215. Southern's parent company, Energy East, was acquired by Iberdrola who does not have a stock option plan.
216. There is no stock plan and the economy has not recovered sufficiently to assume that a stock option expense of $56,000 is reasonable.
217. No evidence supports the Company's expectation that Iberdrola would grant stock options to executives or non-executives for them to exercise during the rate

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year.
218. Southern's qualified pension plan expense increase has little to do with Southern's overall management of its qualified pension plan.
219. Southern has taken steps to mitigate the pension cost increase.
220. The Company delayed implementation of the cash balance formula for salaried employees for two years after it had modified the union plan.
221. There is an upward trend in the discount rate and as such it would be consistent to assume that the trend would continue; therefore, a 6.25% discount rate is consistent with the current trend.
222. The pension discount rate is independent from the other assumptions.
223. The pension discount rate has changed over time while the salary scale and expected return on assets have stayed constant.
224. The Company's pay increase cycle for executive and salaried employees is typically 18 months or longer.
225. Since the 4% is a compound number, the 18-month salary cycle is not incorporated in the 4% assumption and has the impact of overstating the salary scale.
226. Southern assumed a 4% annual salary increase in its qualified pension plan calculations rather than an 18-month schedule.
227. Decreasing the salary increase assumption from 4.0% to 3.5% and increasing the discount rate assumption change from 6.1% to 6.25%, the Department, adjusts the qualified pension plan expense downward by $189,695 to $1,606,376.
228. If ratepayers are being charged for pension expenses, they are providing the cash for a pension contribution.
229. Non-qualified pension plans do not meet the qualifying criteria under the Internal Revenue Code of the United States.
230. The costs included for the EEC SERP and EEC EX are entirely related to Southern's president and should be disallowed based on the current economic climate and ratepayers should not be asked to fund this cost associated with an excessive benefit plan.
231. Ratepayers should not fund generous benefits in these difficult economic times.
232. Southern funds the salary and pension of persons who are not employees of the Company.
233. The Southern BOD Plan funds benefits to former members of its BOD who no longer serve the firm.
234. During their tenure, the members of the Southern BOD were not considered company employees.
235. During the past time period that Southern's BOD members provided services to ratepayers, a cost would have been accrued on Southern's books that would have paid for projected future provisions of the benefits under the Southern BOD Plan.
236. Southern's request for amortization of past non-qualified plan regulatory assets should be disallowed.
237. The practice of providing pension benefits to non-employees is questionable.
238. The Southern SERP, BEP, and DC Plans provide benefits to two employees and pay retirement benefits over and above the internal revenue code with eligibility the same as the qualified plans.
239. Ratepayers should not fund benefits that are over and above the Internal Revenue Service (IRS) code in these difficult economic times.
240. The Company did not comply with the Departmental request to report the expenses of the six non-qualifying plans separately under Late Filed Exhibit No. 82.
241. The Non-Qualified Pension Plans regulatory asset should be removed from rate base since they should not be passed on to ratepayers.
242. Ratepayers should not have to fund excessive benefits such as car allowances for the Vice President and senior corporate counsel in these difficult economic times.
243. The regulated utility industry should not be immune to the realities of the present economy.
244. The GIP, PIP, and Key incentive programs are made to managers and higher-level supervisors.
245. The Company managers and executives should perform to the best of their ability as a condition of their employment and additional compensation for managing effectively should not be required.
246. Incentive payments that are directed almost exclusively to upper management and based on attaining acceptable or expected performance do not provide any benefit to ratepayers.
247. The lower level supervisors are eligible for the PIP

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while only higher level executives are eligible for the Key plan.
248. Director and officer insurance is purchased by a company to insure against claims generated by losses resulting from the illegal or improper actions of its executives and protects the company's shareholders.
249. The Department notes that although a comparison of UI's rate case cost for total outside services of $783,000 and the Company's request for $2,000,000 does not provide a sufficient basis for adjustment, the use of experience in-house personnel intimately knowledgeable of the Company practices and available for day-to-day and recurring regulatory activities is compelling.
250. The Department cannot condone the use of duplicative and potentially excessive outside legal services from two national law firms, which represented the Company along with internal counsel during the proceeding.
251. The conservation consultant's work and findings were readily available through the ECMB.
252. The $400,000 pension and OPEB consultant cost estimate appears high compared to the consultant's actual billings through April 18, 2009.
253. The Company's ROE expert witness merely confirmed the capital structure.
254. The ROE expert witness testimonies are practically and essentially the same for both Southern and CNG.
255. The Department does not question the Company's need or requirement for expert witnesses or legal advisors; but the high costs for these witnesses and legal advisors needs to be evaluated for prudency.
256. $1,580,000 for outside services for a single rate case, regardless of its complexity, should be a sufficient amount to provide this Company with adequate expertise to present its case.
257. The Department alerted Southern to a substantial number of errors and inconsistencies in its original filing that the Company was compelled to correct.
258. Affiliate charges included costs directly charged or allocated to Southern by the EEMC and USSC.
259. The Company requested $228,928 associated with the allocation of payroll expenses for filling vacant and proposed new positions at EEMC and USSC from the test year to the rate year.
260. The Company made the appropriate deduction regarding incentive compensation.
261. The deduction of the non-qualified pension expenses is appropriate for the Company's affiliates.
262. The loan interest charge of $137,640 between EEMC and USSC is overstated.
263. The Company's cost of short term debt is a better proxy for its working capital borrowings than an affiliate debt rate which approaches 11%.
264. The Department rejects the interest rate of 10.7% used by EEMC and instead uses Southern's cost of short-term debt percentage of 2.48%
265. No evidence supports the position that Iberdrola, whose stock shares are only publicly traded in Europe, has any plan to establish stock option compensation plan for Energy East's subsidiaries.
266. The stock option expense allocated to Southern is a non-recurring expenditure and should not be included in allocated charges proposed for the rate year.
267. The affiliate services provided by EEMC and USSC to Southern demand a Department investigation pursuant to Conn. Gen. Stat. §16-8c.
268. The Company made adjustments for incentive compensation of $330,000 allocated to Southern by EEMC but did not make an adjustment for stock option expenses that were allocated by EEMC and USSC..
269. Environmental remediation means coal tar remediation only and shareholders would be responsible for other environmental remediation expenses outside the test year or between rate cases.
270. The Pine Street site in Bridgeport remediation is approved because it is test year coal tar remediation.
271. The Chapel Street site expense of $1,055,060 ($892,012 + $163,048) related to the repair of the Mill River's storm water system and site remediation because this environmental remediation expense is not for coal tar and is a non-reoccurring expense.
272. The Marsh Hill Road property expense is not for coal tar remediation, but the result of a leaking hydraulic garage lift fluid, which is a non-reoccurring expense.
273. The expense of $51,736 for asbestos remediation at the Trumbull LP facility is not coal tar related
274. The Company must not only establish the legitimate occurrence of a given expense in the test year, but also the likelihood that the expense is representative of

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future operation for it to be reoccurring and a proper rate year expense.
275. The contract between Cellnet and Southern sets the performance standard for meter readings which requires that the meter reads every day be accurate up to a 96.5% level for the first 12 months and 98.8% level thereafter.
276. Customers that do not receive the expected service from a DDM should not pay a DDM charge.
277. The revenue requirements model used by the Department adjusts expenses, including taxes for the impacts of specific adjustments on uncollectible expense, gross earnings tax, income taxes and interest expense synchronization.
278. The impact of all the adjustments made by the Department is shown in Tables II and III in the Appendix.
279. The Company double counted the manufacturing rebate (MR) and erroneously added back NFM mechanism revenue and Firm Transportation Service (FTS) surcharge to the base revenue at present rates for calculating GET expense.
280. The Company's attempt to add back the NFM and FTS surcharge would double count the amounts associated with these items and grossly overstates the pro forma revenue at present rates for calculating GET expense.
281. The Company incorrectly included the net revenue from interruptible and off-system activities in the total pro forma revenue at present rates.
282. The Company did not make the Application's revenue request PGA neutral.
283. The ultimate impact of revenues from non-firm and ancillary activities on the PGA gas costs is net of applicable GET.
284. The non-residential revenue at present rates consist of all revenue from C&I customers including revenue from manufacturers who qualified for the 5% GET rebate.
285. The total pro forma revenue at present rates should only be grossed up for the amount of MR that would be credited on industrial customers' bills.
286. The Department recalculates the Company's allowed GET rate to be 4.1138% and reduces the proposed GET expense at present rates by $833,790.
287. Due to SFA, the Department increases GET expense by $175,293, which is the SFA's additional revenue of $4,261,093 times the allowed GET rate of 4.1138%.
288. The proper administration of municipal property taxes requires the Company to take up any subsequent differences in property tax valuation with the appropriate municipality.
289. The proper administration of municipal property taxes requires the Company to take up any subsequent differences in property tax valuation with the appropriate municipality.
290. The proposed municipal property tax expense for the rate year is overstated.
291. There is insufficient evidence provided in this proceeding to substantiate an average increase to the mill rates of the municipalities in the Company's service territories between the test year and the rate year.
292. The pro forma payroll tax expense was not adjusted despite Southern's proposed decrease to payroll expense.
293. The GRCF determines the change necessary in revenues to produce the required change in allowed operating income.
294. 4.1138% represents the allowed GET percentage.
295. The Department includes the allowed GET and uncollectible expense percentages into its calculation of the Company's allowed GRCF.
296. The Department uses the most recent cost of gas to set the rate year cost of gas.
297. The reduction in the cost of gas reduces the carrying cost of gas associated with storage gas.
298. The Company's full **decoupling** proposal compensates the Company for any type of reduction in consumption, such as warmer weather, customer loss, a deteriorating economy as well as permanent and price-induced conservation.
299. The very large **risk** of revenue instability from **decoupling** is shifted from the Company to the customer.
300. It will require at least a 100 basis point reduction in ROE (approximately a $4 million reduction in revenue) to provide customers with commensurate **risk** compensation.
301. The enlarged conservation expenditures that the Company points to as the **decoupling** quid pro quo, will be paid for by ratepayers, who will also experience upward pressure on rates as UPC declines further.

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302. The Company's full **decoupling** proposal guarantees a revenue stream while providing the Company the freedom to file a rate application at will.
303. The Department chooses to satisfy the Act by means of rate design.
304. The proposed volumetric Sales Services Charge (SSC) and Transportation Services Charge (TSC) are being converted to demand charges.
305. Existing, time-tested rate-setting principles afford Connecticut gas utilities ample opportunity to provide safe and efficient service while offering a reasonable opportunity to earn a fair rate of return on investment.
306. The Company complied correctly with the vast majority of COSS allocation rules.
307. Earning the same class-level ROR from all assets within a class, whether a merchant or distribution component, enhances customer equity by insuring all customers are assigned costs in accordance with similar asset utilization.
308. Demand charges should be derived using the demand units that constitute the demand allocator used within the COSS, which typically is different than pro forma demand billing units.
309. The Department has many of the same rate design goals as the Company.
310. The Department continues to increase fixed charges across all rate classes, which satisfies **decoupling** of sales from revenue as required by Public Act 07-242 § 107.
311. Rate stability is critical in this case.
312. It is essential to consider customer impact in terms of individual rate components and most importantly as function of the total bill.
313. The Department is concerned about rate stability because less than one year has passed since the Company's most recent rates went into effect.
314. Certain adjustments to the Company's revenue requirements in the instant case will require significant changes to the proposed class revenue allocations and proposed charges.
315. The current block breakpoints remain reasonable.
316. To the extent there are any unintended adverse bill impacts resulting from the general rate design directives given by the Department, proposed modifications in the Rate Design Plan may be considered.
317. The proposed rate design is counterproductive to the progress made in the recent proceeding where half of the firm rate classes were within 1% of the system average ROR.
318. The Department does not have the appropriate COSS information to approve actual rate class revenue; but can approve or provide guidance with respect to the rate class ROR.
319. The Department is concerned about the recent rate impact of Rate SGS resulting from the migration of large customers from this class.
320. Setting full COSS supply rates for each rate class is consistent with prescribed PGA procedures.
321. Bill comparisons at proposed and final rates in the instant case will best replicate actual bills that are calculated using PGA supply rates.
322. Equal SSC and TSC demand charges should be implemented for each of the three C&I rate classes.
323. The analysis done in response to Interrogatory GA-385, which gave the Company concern over bill impacts and potential customer shift, is not representative of the situation that exists under final rates in the instant case.
324. The introduction of a demand-based SSC and TSC satisfies the **decoupling** pursuant to Public Act 07-242 §107, while stabilizing gross margin recovery for the Company.
325. Given the recent increases in revenue allocation and fixed charges for the Rate RSG class, the Department finds the proposed Customer Charge of $19.75 far too aggressive.
326. The Department believes that Southern's proposed Rate RSG Customer Charge of $18.50 is excessive and would compromise rate stability for its largest class of customers.
327. Given the large increase in the Rate RSH Customer Charge approved in the Rate Design Decision, the Department believes a charge of $14.00 is more reason- able.
328. The Department extends to Rate RMDS its long standing DDM requirement for C&I customers with annual consumption greater than 500 Mcf.
329. Customers above the annual threshold would benefit from daily consumption data as they have a greater ability to modify daily usage than those customers with lower annual consumption.

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330. For smaller customers, the possible cost savings from modifying peak day usage are much less than the costs associated with paying a monthly DDM charge.
331. The algorithm used by Southern to determine the peak day usage for customers is sufficient.
332. Prior to the elimination of C&I customer rate choice, Southern previously maintained a sub-group of Rate SGS customers that were not required to have DDMs.
333. Approximately 669 (1,029 x 0.65) of Rate RMDS customers can reasonably be expected to have a DDM requirement.
334. The Demand Charge for Rates GS and the Customer Charge and Demand Charge for Rate LGS were set by the Company at less than the proposed 100% COSS-based rates.
335. The Department modified the Company's approach in favor of carrying the COSS derived demand charges forward to revenue exhibits without alteration, save gross receipts tax (GRT), making the statement "100% COSS rates" technically accurate.
336. The Department remains concerned about the negative rate impact that resulted from the direct assignment of high volume C&I customers out of Rate SGS as previously approved in the Rate Design Decision.
337. The Department believes that a $15.00 increase for the Customer Charge for Rate SGS is far too aggressive, and believes one third of the proposed increase is more appropriate at this time.
338. The proposed Rate GS Customer Charge of $75.00 is reasonable, and therefore approved.
339. It is appropriate to reduce the proposed revenue allocation dramatically to reduce subsidization by Rate LGS.
340. The approved charges herein builds upon the rate design approved in the Rate Design Decision.
341. Rate class revenue responsibility will be assigned in a fashion that reduces cross-subsidies between rate classes to the extent possible.
342. The Department approved increases in fixed charges for all rate classes that are not already at 100% cost based reduces intra-class subsidies and increases fixed cost recovery by the Company.
343. Actual fixed cost recovery will not be known until the Company submits its proposed Rate Design Plan.
344. The introduction of demand SSC and TSC also decouples sales from revenue while stabilizing gross margin recovery for the Company.
345. The WNA is a rate mechanism that adjusts the non-gas portion of customers' bills to offset the influence of weather on those bills.
346. Southern has been the only Connecticut LDC to be allowed a WNA mechanism.
347. Southern benefits significantly from the WNA, which is currently in its 16th year.
348. Southern received a total of $43.6 million in net WNA revenue through March 2009 while ratepayers benefited in only three of those 15-plus years.
349. The average ROE with the WNA was 11.15% versus 10.22% without a WNA, an increase of 93 basis points (11.15% - 10.22%).
350. The WNA has not performed as the Department had believed it would when its continuation was allowed in the 2000 Decision.
351. The WNA has been one-sided in favor of the Company.
352. The 85 basis point average bonus to the ROE has now increased to 93 basis points and the Company is nearly $44 million better of with the WNA than without.
353. Unless the weather pattern turns colder than normal for the majority of the remaining years of the 30-year cycle, the revenue flows will have little or no opportunity to average-out, and the benefit between ratepayers and the Company will not equalize as expected.
354. There is no guarantee that the current weather trend will reverse itself, the Department finds that continuing the WNA would not be in the public interest.
355. The most accurate method the Department could have used would be the sales and hourly loads for each customer included in the Hurdle Rate calculation.
356. If the Department were to use the Hurdle Rate calculations provided and extrapolate those to each customer class, the test year revenue adjustment would be between $429,000 and $1.38 million over the eight year period evidencing incorrect MDQ billings.
357. The Department accepts the Company's test year revenue adjustment of $270,502 despite its methodological infirmities.

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358. The Department finds it improbable that the Company was unaware of the scope and size of the MDQ issue for so long and was imprudent.
359. The failure to bill and collect Demand Charges from the under billed customers also affects other customers.
360. If revenues from the under billed customers are not included in rate case sales projections, the effect of understated sales is increased rates.
361. The Hurdle Rate model included a salesman's commission rate for residential rate classes of 45% and 15% for C&I rate classes.
362. The Company did not provide a revised Hurdle Rate using the correct depreciation rates
363. The Hurdle Rate model inputs does not comport with the Department's expected calculation of the CIAC.
364. The NFM incentive structure in place for many years has been much more generous than necessary to accomplish the goal of maximizing NFMs.
365. There has been no reduction in reward to the Company in return for the **risk** that was shifted to ratepayers under the NFM mechanism.
366. The current NFM mechanism in place has some inherent flaws.
367. If the NFM threshold is forecasted too high and the Company believes it is unattainable.
368. The Company has little incentive to maximize NFM regardless of where the sharing percentages are set.
369. The methodology in place for forecasting the annual NFM threshold is not forward looking, but rather, based on historical information.
370. An alternate NFM mechanism that starts with the very first sale is far more appropriate.
371. Although the level of incentive will vary from year to year, some level of incentive will be achievable by the Company each and every year, and the incentives will be directly related to the actual NFM attained.
372. There is no longer any **risk** to the Company for any level of NFM earned and the level of NFM achieved is largely a function of market conditions outside of Southern's efforts.
373. A NFM sharing percentage of 1% under the new mechanism is reasonable.
374. The new NFM mechanism will provide some incentive level each and every year, more commensurate with the Company's activities, and less on market conditions.
375. The extraordinary market conditions recently experienced in the energy markets have resulted in interruptible rates that were higher than firm service rates.
376. The recent short term, extraordinary spread in pricing does not result in the need to increase the service commitment period for Rate IS customers at this time.
377. The Department has long and firmly held policy that encourages the maximization of interruptible sales.
378. The margins offset the costly infrastructure designed to meet the demand of firm customers.
379. Requiring customers to stay on a firm rate for a longer period will diminish achievable margin levels and result in less available capacity to serve normal firm growth.
380. The Department finds there is no significant threat of stranded costs specifically related to the recent interruptible switching activity.
381. The Department expects that the Company will continue to use its authority under the Rate IS tariff to protect the integrity of its gas supply and avoid imprudently acquiring new supply sources for the purpose of satisfying short-term demand.
382. The Department believes that it may be more administratively efficient to present certain terms in a general definitions section of the tariffs.
383. It is administratively inefficient to create a definitions section just for a handful of terms solely for the purpose of eliminating redundancy in the tariffs.
384. A more all-encompassing definitions section may be useful to customers.
385. Seeing that Southern will experience an overall decrease to its revenue requirement, now is the time to change the breakpoint consumption level between Rates GS and LGS to 30,000 ccf.
386. The Department does not accept the Company's argument that it would be somehow burdensome to the affected customers to be "snapped back" into Rate GS.
387. The Department noted an error in Section 1, Availability of Southern's C&I tariffs regarding the basis of customer rate class assignment.
388. The 10-year average expenditure for all mains and

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services replaced is artificially skewed upward and is not reflective of the actual expenditures for the CI/BS Program.
389. As non-state-of-the-art pipe ages, the leak rate tends to increase over time.
390. Southern is not replacing enough of the older pipe to lower the leak rate.
391. The replacement rate is only keeping even with the amount of leakage.
392. To improve leakage rates, it is necessary for Southern to replace more of the lower integrity pipe.
393. As the infrastructure has aged, the need for more extensive programs to address replacement of non-state-of-the art materials has increased.
394. The Department has been actively involved in pipeline safety issues, both in hearings and as part of its on-going oversight responsibilities for pipeline safety.
395. There is no need for a formal study to demonstrate what the Department has already determined.
396. The Department remains concerned with the state of affairs involving **risk**-based pipeline safety programs, leak response, leak repairs and excavation damage.
397. The Company's standard bill form and termination notice are in conformance with applicable regulations.
398. Although Southern capably tracks those complaints that are escalated to a supervisor, the Company would benefit from reviewing and tracking all complaints.
399. The Department found that many utility customers are having increasing difficulty in paying their utility bills.
400. The Department has no objection to Southern's proposed change from 35 to 45 seconds for its ASA.
401. The hours of operation for the payment locations are not posted on Southern's website.
402. The bill payment service through Kubra is a beneficial service, which provides customers with an immediate option for payment.
403. A customer survey gives the Company insight into its performance; however, it is only a snapshot of customer views.
404. By reviewing all customer complaints and inquiries, Southern can work toward improving problem areas.
405. The existing 2009 Plan program objectives are adequate at this time to meet customer needs and the state's overall goals related to natural gas conservation.
406. Not all of Southern's conservation programs are fully subscribed at this time.
407. The Company's proposed expansion in outreach efforts is unnecessary at this time.
408. Energy efficiency proposals are best suited for the annual review of the LDCs' joint conservation plans, not in a general rate case.
409. Energy efficiency proposals should be proposed in the annual joint conservation plan.
410. It is important for the Company to investigate alternative funding sources, rather than relying solely on ratepayer funding.
411. To determine a rate of return on rate base that is appropriate for Southern's overall cost of capital, the Department first identifies the components of the Company's capital structure.
412. Short-term debt is a permanent source of capital for Southern in its capital structure.
413. Due to Southern's reliance on short-term debt, it should be included in its capital structure for ratemaking purposes.
414. Since Southern's short-term debt is used to fund gas supply purchases then an adjustment for AFUDC is not necessary.
415. By not reducing common stock equity by the accumulated amortization of goodwill, the Company is overstating the equity portion of its capital structure and indirectly overstating both its ROE and ROR.
416. Both the ROE and ROR eventually determines the Company's allowed revenue requirement.
417. The Department adjusted Southern's capital structure for the amortization of goodwill.
418. Based on the journal entries provided by the Company to eliminate the effects of both the goodwill recorded to paid-in-capital and goodwill amortizations, the Department determines that the Company must have made initial journal entries to record both transactions.
419. Any journal or elimination entries done in a consolidated financial report should not have any impact on the calculation of the Company's regulatory common stock equity amount.
420. Southern's proposed capital structure is equity rich when compared to the proxy groups and other regulated

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utilities.
421. Dr. Woolridge's short-term debt cost of 1.75% is too low because it is not reflecting the cost of the short-term debt based on the Company's actual cost to date.
422. Southern's proposed cost of short-term debt of 2.48% is reasonable and approves the 2.48% cost of short-term debt.
423. Southern's efforts to lower its cost of long-term debt is admirable.
424. The analyses undertaken by Dr. Makholm and Dr. Woolridge to determine the investor required ROE contained differences within the methodologies and employment of multiple methods of valuation.
425. The principal issues between the studies performed by the two cost of capital witnesses concerned the yield calculation and growth rate used in the DCF model, the **risk** premium assigned to the Company's common equity and the level of reliance on each modeling method to determine overall valuation.
426. The Department carefully reviewed and considered the testimony of the two consultants, and performed its own cost of capital calculations.
427. Based on the thin arguments and contradictory testimony by the Company, the Department gives little weight to the Company's position that a 12.2% ROE will result in an "A" bond rating for Southern any time in the foreseeable future.
428. If the Company wishes to elevate its bond rating, there are several performance metrics within the Company's control, to which it may apply its efforts.
429. The Department considered both comparable groups from Dr. Makholm and Dr. Woolridge.
430. The Department used Dr. Woolridge's nine member comparable group.
431. The Department believes that the investment community considers Dr. Woolridge's comparable group to be LDCs since these utilities are each listed as natural gas distribution, transmission, and/or integrated gas companies in AUS Utility Reports and listed as natural gas utilities in the Standard Edition of the Value Line Investment Survey.
432. The Department considered the criterion that assesses the **risk** and overall comparability to Southern for the nine member comparable group.
433. The Department finds that Alliant, Avista Corp., MGE Energy, NStar and Wisconsin Energy **risk** comparability was not comparable to a regulated LDC.
434. The Department finds that Alliant, Avista Corp., MGE Energy, NStar and Wisconsin Energy, having less than 50% gas revenues, do not qualify as being comparable to a LDC such as Southern.
435. The Department performed its own DCF calculation using traditional DCF methodology.
436. To develop the dividend yield of D_1/P_0 the Department used the dividend yields for the period November 2008 through April 2009 and the Department's modified comparable group.
437. In its DCF calculation, the Department recognized that dividend yield is the most volatile component of the DCF calculation, and therefore used a six-month average dividend yield.
438. A spot yield should not be used since it is given to aberrations in that one day, which may not truly reflect investor stock price expectations.
439. The Department used recent data to reflect the current economic climate.
440. In choosing the growth rate, the Department used a combination of the Value Line projected growth in earnings of 4.60%, the internal growth methodology using Value Line numbers of 11.80% ROE and 44.6% retention growth for an internal growth rate of 5.2%, and historic five-year growth rate of 7.10%.
441. The growth rate figure used by the Department is 5.46%.
442. Investors consider past performance in evaluating the future as well as analyst forecasts.
443. The Department used Value Line since it is a well respected source of investor information.
444. The Department adjusted the dividend yield by one-half of the expected growth rate to reflect growth over the coming year.
445. The Department considers the YPG model to be a variant of the DCF model, and has not previously recognized the employment of the YPG model in any rate case Decision for rate-making purposes.
446. The Department's primary purpose in developing its DCF model was to test the validity of the witnesses' testimony, not to endorse that method's use in this docket.
447. The DCF model may yield wildly fluctuating out-

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puts based on input variations.
448. The most appropriate use of DCF modeling is to value the stock of large, publicly traded firms.
449. The CAPM technique is more well-suited as a predictor in this docket than the DCF modeling.
450. The Department utilized the DCF results in its estimated average of the cost of capital.
451. The Department applied the CAPM to its comparable group using the standard formula of $K = R_f + B (R_m - R_f)$.
452. The Department believes the CAPM calls for a long-term **risk** free rate, which would be the 30-year Treasury.
453. In the CAPM formula, the Department used an average of forward looking returns found in the record.
454. The Department used Dr. Makholm's $(R_m - R_f)$ since it is forward looking and makes use of projected data for the entire S&P 500, which is a good proxy for investor expectations.
455. The use of historical **risk** premiums in the current financial crisis makes determining the proper historical period to use problematic.
456. The Department finds a market **risk** premium that is forecasted rather than historical better reflects investor expectations.
457. The Federal Reserve Survey also reflects investor expectations since it is a survey of financial forecasters which shows a 6.50% return on the market R_m.
458. In attempting to track forward looking investor expectations, it is necessary to use both the Company's and OCC's equity **risk** premiums.
459. The Department takes a simple average of the CAPM using the Company proposed **risk** premium, 10.83%, and the CAPM using OCC **risk** premiums, 6.30%, for a CAPM investor expected ROE of 8.57% [(10.83% + 6.30%)/2].
460. The Department has not provided an adjustment for flotation costs given the particular circumstances of the instant case.
461. Southern is a wholly owned operating subsidiary of Energy East and has not issued equity on its own since 1996 and will not be issuing it in the future.
462. Since market to book equity ratios for LDCs is in excess of 1.60, there should be no adjustment for flotation costs as there is no dilution to stockholder's equity.
463. The modeling employed by the Department in this proceeding produced a DCF value of 9.98% and CAPM value of 8.37%.
464. The Department rejects the Company's fundamental argument that the appropriate analysis under Conn. Gen. Stat. § 16-19(g) is to compare the ROE resulting from the interim rates reflecting the imposition of the rate credit and the ROE found appropriate in the final Decision herein as this construction would convert the surcharge provisions of § 16-19(g) into an ROE maintenance mechanism in contravention of traditional ratemaking principles.
465. The parallels between the interim rate decrease and increase statutes are unmistakable.
466. Nothing in the interim rate increase section requires the Department to guarantee a specific ROE, nor to construct a distinct revenue requirement for an ERP period, as the Company insists must be done for the interim rate decrease.
467. The interim rate increase section specifically requires the Department to compare the rates collected on an interim basis to the amounts which would have been collected pursuant to the rates finally approved.
468. Reasons exist to treat §§ 16-19(d) and 16-19(g) differently in this regard with respect to interest.
469. The IROD directs the Company to provide information with which it will make a Decision but does not state that the information provided would constitute the only information on which the Department could rely.
470. The Company's interpretation of the IROD suggests that not all the information in the current record can form the basis for making a final decision in this matter.
471. The Department used the entire record in this proceeding to form the basis for its Decision and declines rely on only selected parts of the record to form its conclusions.
472. Southern's preferred approach to interpreting Conn. Gen Stat. § 16-19(g) is the most troublesome form of retroactive ratemaking because it picks and chooses which parts of the historic data, they call actual data, and comingles it with prospective and forecast data.
473. The 5.74% ROE the Company quotes in its Written Exceptions (See e.g., pp. 5, 8) is not merely a function

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of the IROD but includes the expenses that the Company chose to incur during that period.
474. The Company has failed to aggressively manage its rate year expectations, expenses, cash flows, collection efforts and investment activities.
475. The Company rate increase request does not reflect current economic conditions.
476. When a gas customer must pay such a large proportion of all their income to keep warm and cook, it is not surprising that they cannot afford to pay their bills.
477. The Company's deficient application of The Uniform System of Accounts, aggressive ratebase addition requests, unprecedented rate case expense request and historically dismal (though recently improving) uncollectible balances and collection practices do not suggest to the Department that the Company is at all mindful of the costs it imposes on Connecticut.
478. The Department finds it nearly incomprehensible that substantial MDQ and demand charges and revenue misallocations continued for several years undetected.
479. The Department, State of Connecticut and the Company's ratepayers simply cannot maintain the status quo operation of the Company.

V. CONCLUSION AND ORDERS

A. CONCLUSION

Based on the evidence presented in the record, the Department concludes the following.

Allowed revenues of $376,174,556 are appropriate for Southern and is a reduction of $46,640,574 from the adjusted request of $34,179,309. The Company is allowed a rate base of $436,709,282 and ROE of 9.26% for a weighted cost of capital of 8.05% using an allowed capital structure containing a 52.00% common equity component and a 48.00% debt capitalization component. These revenue requirement and rates, when applied to the rate base are reasonable and will produce operating income sufficient for Southern to operate successfully, serve its ratepayers, maintain its financial integrity and compensate its investors for the risk assumed.

Hundreds of bills issued to C&I customers failed to include the correct demand charges which resulted in the Company not collecting the proper amount of revenues; therefore, pursuant to Conn. Gen. Stat. § 16-19e(a)(5), the Company's ROE is reduced by 10 basis points to reflect imprudent management.

New rates will become effective upon written Department acceptance of the final rates compliance filing for usage on and after August 19, 2009. Coincident with new rates, the WNA and the interim rate credit will terminate. At that time, a debit surcharge $0.0161 per CCF will be applied to firm customer bills until the Department determines that it is no longer necessary.

Separating commercial from industrial customers in the UPC and customer models will result in forecasts that are more accurate. The Company has improperly earned a rate of return on numerous expense entries in rate base for 38 years. It is wrong for Southern to include expenses in rate base. Southern did not comply with its purchasing policies. The Department applies the depreciation rate associated with Account 390.1, Structures and Improvements to all assets included in Account 391.1. All property records included in rate base will be audited to determine their validity and prudency. The Meter Relocation Program is terminated.

The Department will review the prudency of Southern's collection efforts related to inside meter access issues including any carrying costs for accounts with inside meters or any other relevant charges or costs. The Department disallowed the capital expenditures associated with the HVAC control system, a second emergency generator, the construction work associated with the Pipe Yard and the workplace office construction at the Orange Operations Center. A new business expenditure of $4,056,000 most reflects the Department's expectations for the rate year. The Department disallows the total DG and peaking expenditures of $3.1 million. It is more appropriate to keep uncollectible expense in the lead/lag study and assign it a more reasonable expense lead. The Department removes insurance and property taxes from prepayments in rate base and includes them in the lead/lag study.

The Department determined that the Company over-

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stated its GET expense and rate by double counting the MR, NFM and FTS surcharge revenues in its calculations. The Department reduces the proposed collection lag an additional 4.44 days because of company policy changes and makes a mitigating reduction to the uncollectible expense lead. The Department halts additional deferrals of Department docket expenses. Ongoing annual hardship expense should remain at the current level. The Department disallows all expense associated with the Southern BOD Plan, but approves the Company's 401(k) plan. The allowed GRCF is 1.77124. The Department increases total pro forma gas costs by $2,186,834 and abolishes Southern's WNA.

The Department accepts the Company's test year revenue adjustment of $270,502 despite its methodological infirmities and eliminates the annual threshold in the NFM sharing mechanism in favor of a lower sharing percentage from the very first dollar of NFM earned. The Department establishes a modified NFM mechanism.

It is in the public interest to replace facilities that are not state-of-the-art. The Department approves Southern's CSR training and its application of Conn. Gen. Stat. § 16-259a(d). Southern's bill estimation comports with Conn. Agencies Regs. § 16-3-102 and its security deposit policy for residential and C&I customers conforms to Conn. Agencies Regs. § 16-3-200 and § 16-11-32a.

The Department finds that the 2.48% cost of short-term debt is reasonable. The Department approves Southern's embedded cost of long-term debt of 7.19%. The Department denies the 22 basis point adjustment for flotation costs by Southern. The 9.36% ROE is a fair rate and is in the range of reasonableness developed by Dr. Woolridge of 7.00% and Dr. Makholm of 12.51%. The Department finds that cost of capital rates, when applied as herein to the rate base reasonable for the Company, should produce operating income sufficient for Southern to operate successfully and serve its ratepayers, maintain its financial integrity, and compensate its investors for the risk assumed.

Pursuant to Conn. Gen. Stat. § 16-19(g), the "rates finally approved," as compared on a per CCF basis to the interim rates, are $0.0161 higher and the Company is entitled to a debit surcharge of $0.0161 per CCF ($0.0621 - $0.0460). The surcharge will commence October 1, 2009 if no appeal has been taken.

B. ORDERS

For the following Orders, submit one original and five (5) copies of the required documentation to the Executive Secretary. Submissions filed in compliance with Department Orders must be identified by all three of the following: Title, Docket Number, and Order Number. Compliance with orders shall commence and continue as indicated or until the Company requests and the Department approves that the Company's compliance is no longer required after a certain date.

1. Effective with the issuance of the instant Decision, Southern shall apply the depreciation parameters associated with:
   a. Account 390.1 to all assets included under Account 391.1; and
   b. Account 396 to all assets included under Account 392.
2. Effective with the date of this Decision, the Company shall change its charge-off policy by accelerating its charge-off period for uncollectibles from six months to three months.
3. Effective with the issuance of the instant Decision and commensurate with new rates going into effect, Southern shall discontinue the existing interim rate credit.
4. Effective with the issuance of the instant Decision and commensurate with new rates going into effect, Southern shall discontinue the WNA.
5. Effective with the issuance of the instant Decision, if the Company receives a customer inquiry regarding gas conservation programs, the Company shall record customer information for referral to its C&LM department.
6. Effective with the issuance of the instant Decision, the Company shall begin contacting all landlords, managers, agents and lessors regarding delinquent accounts in their buildings. Southern will request access to the respective meter(s) to terminate service for-non payment in accordance with applicable statutes and regulations.

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7. Effective with the issuance of the instant Decision, the Company shall apply a Disconnection Charge and a Reconnection Charge as described in the tariffs for those customers for whom Southern must terminate service resulting from a collection issue.
8. Effective with the issuance of the instant Decision, the Company shall not levy a DDM charge on any customer whose meter readings do not meet the contract standards.
9. Effective with the issuance of the instant Decision, the Company shall include Service Transfers in rate base as a capitalized item depreciated over the service life of the asset as discussed in Section II.C.2.f. Service Transfers.
10. Effective with the issuance of the instant Decision, the Company shall use only Department approved tariff terms and depreciation rates in its Hurdle Rate model as discussed in Section II.L. Maximum Daily Quantity.
11. Effective with the issuance of the instant Decision, the Company shall record customer information for referral to its Conservation and Load Management Department on all customer inquiries about conservation programs via phone or letter as discussed in Section II.Q. Energy Efficiency.
12. Effective with the issuance of the instant Decision, Southern shall make pension contributions as discussed in Section II.E.b. Funding for Qualified Pension Plans.
13. Within 30 days of the issuance of the instant Decision, the Company shall furnish an accounting document detailing the projected expenses of the PIP and Key plan, showing what portion of the $137,546 total is allocated to each of the two plans.
14. No later than July 31, 2009, Southern shall add the hours of operation for the payment locations to the website list.
15. No later than July 29, 2009, the Company shall file for approval with the Department a compliance COSS and Rate Plan including all revenue proof exhibits and bill comparisons. The Company shall also file five (5) complete sets of current tariffs (scored and unscored) in loose-leaf notebooks incorporating all rate and language changes approved by the instant Decision.
16. No later than August 15, 2009, Southern shall submit an exhibit that calculates the depreciation expense and revenue requirement associated with:
a. Account 391.1 using the proposed depreciation parameters from Account 390.1; and
b. Account 392 using the proposed depreciation parameters from Account 396.
17. No later than August 3, 2009 and quarterly thereafter, the Company shall submit to the Department a tabulation of suspected gas leak call responsiveness reports for the prior quarter.
18. No later than August 3, 2009 and quarterly thereafter, the Company shall submit to the Department a tabulation of the Grade 2 leak status (beginning balance, leaks detected, leaks repaired, other disposition, ending balance) for the prior quarter.
19. No later than August 3, 2009 and quarterly thereafter, the Company shall submit to the Department a tabulation of third-party damage incidents, number of Call Before You Dig tickets, and the number of damages per thousand tickets for the prior quarter.
20. No later than August 3, 2009 and quarterly thereafter, the Company shall submit to the Department a pipe replacement program report for the preceding quarter. The report shall include year-to-date totals for the fiscal year through the preceding quarter.
21. No later than August 15, 2009, Southern shall file a copy of its current policy regarding the sale of assets to be retired from rate base.
22. No later than September 11, 2009, the Company shall submit to the Department a monthly tabulation of actual sales to which the interim rate credit was applied and the Company's calculation of the total surcharge revenue to be collected from customers going forward.
23. No later than September 15 and November 16, 2009 and January 15, 2010, provide the total full time equivalent employee headcounts and vacancies as of August 31, 2009, October 31, 2009 and December 31, 2009, respectively. Following the December 31, 2009 filing, provide the data on a quarterly basis on the 15th day subsequent to the close of the quarter.
24. Effective with usage on and after October 1, 2009, the surcharge shall commence, absent an appeal, and shall continue until it is terminated by the Department upon full recovery of target surcharge revenue.
25. No later than October 15, 2009 and within 60 days of the end of each calendar year during which the instant Decision remains in effect, Southern shall report to

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the Department information regarding its progress on all collection activities.
26. No later than October 15, 2009 and within 60 days of the end of each calendar year during which the instant Decision remains in effect, Southern shall include in the annual Collection Activities Report an accounts receivable aging detail, number of customers shut-off due to non-payment, number of customers reconnected, number of curb valves installed, number of meters relocated outside and its top 50 commercial and residential delinquent accounts with collection activity details.
27. No later than November 3, 2009, the Company shall prepare and submit a plan to the Department outlining how the Company has and in the future will manage its operational expenses and capital investments that genuinely reflect current economic conditions and which addresses the issues listed and discussed in Section II.T. Current Economic Conditions.
28. Effective November 16, 2009 and monthly thereafter until the surcharge target revenues have been compiled and reported, absent an appeal, the Company shall submit a report, showing the monthly and year-to-date tabulation of surcharge sales and revenues.
29. By January 15, 2010 and annually thereafter, Southern shall provide a report regarding access to inside meters and the results of its collection progress regarding delinquent accounts, as discussed in Section II.C.2.b. Meter Relocation Program.
30. By January 4, 2010, Southern shall perform and file an independent audit on all of the items in each of its rate based accounts as described in Section II. C. Rate Base to ensure compliance with the Uniform System of Accounts. This audit shall:
• determine and identify any rate base items that should be moved from the one rate base account to another rate base account include dates of in-service, dollar amount and description of each item;
• determine and identify any account entries relating to expense items that should be removed from rate base accounts include dates of in-service, dollar amount and description of each item;
• identify and quantify all items in each rate base account that would not be allowed under the Company's current capitalization policy; and
• indicate and identify all of the assets included in the rate base accounts and whether the assets are currently in-service or physically retired and remain out of rate base.
31. Beginning January 15, 2010 and thereafter, Southern shall file an annual report in a spreadsheet indicating the dollar amount of DDM charges billed to customers and the dollar amount of DDM charges also billed to the Company by Cellnet.
32. By March 15, 2010, Southern shall provide the deferred regulatory asset and liability balances as of December 31, 2009 and annually thereafter. Include detailed supports for the amortization expense deducted and for any additions to the deferred balances.
33. Southern shall continue to file the monthly Missing Reads Report as directed in the Cost Allocation Decision, enhanced as necessary, as discussed in Section II.E.17. Daily Demand Metering.
34. In each semi-annual PGA proceeding, the Company shall file a report detailing the monthly level of NFM earned from each source of non-firm activity as well as the sharing levels between ratepayers and the Company's shareholders under the new NFM mechanism.
35. In future rate applications, the Company shall develop separate econometric models for commercial and industrial data. CW
36. In the final rates compliance COSS in the instant case and future COSS filings, the Company shall:
a. calculate FT working capital in accordance with the directives in Section II.J.1. FT Working Capital;
b. use equal merchant and distribution RORs as explained in Section II.J.2. Equal Merchant, Distribution Rate of Returns; and
c. adopt the 100% COSS rate convention in accordance with the directives in Section II.J.3. 100%COSS Demand Charge.
37. In its next rate case, the Company shall file a Depreciation Study that corrects the deficiencies described in Order No. 22.
38. In its next rate case, the Company shall provide a detailed cost/benefit analysis and justify why the credit card bank transaction fee costs should be socialized over all ratepayers rather than be charged directly to those using the service as discussed in Section II.E.7. Speedpay Transaction Fees / KUBRA.
39. In its next rate case, the Company shall provide a re-

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port on the effectiveness of its use of an outbound dialing service to reduce its uncollectible expense as discussed in Section II.E.11. Collection Activities - Outbound Dialing Vendor.
40. In its next rate case, the Company shall file an itemized accounting of the revenues received from ratepayers for DDM services and the costs borne by the Company for services provided by DDM related vendors as discussed in Section II.E.17. Daily Demand Metering.
41. In future rate case filings, the Company shall separate coal tar remediation expenses from all other environmental remediation expense presentations.
42. In future rate case filings, the Company shall use the most recent available 30-year period of Monthly NOAA Data for normalizing sales. CW
43. Southern will no longer need to file NFM testimony in a separate docketed proceeding as directed in the Interim Decision dated March 26, 2008 in Docket Nos. 07-04-01 and 07-10-01.Instead, the Company will file a report in the semi-annual PGA proceedings on the level of NFM earned monthly from each source of non-firm activity as well as the sharing levels between ratepayers and the Company's shareholders as discussed in Section II.M. Non-Firm Margin Sharing.
44. As is current practice, should demand for Southern's conservation programs cause it to potentially exceed its available budget and no alternative funding is available, it shall seek Department approval prior to making additional ratepayer funding available.
45. At the end of each year should the Company underspend on its replacement program, it must include a program in its compliance filings designed to ensure that that the current year's capital expenditure carryovers are wholly used on meaningful replacement programs in the following year.
46. The Company shall add the balance of $1.5 million of the discontinued Meter Relocation Program funds to the CI/BS Program as discussed in Section II.O.1. Cast Iron/Bare Steel Planned Replacement Program.

SOUTHERN CONNECTICUT GAS COMPANY - DN 08-12-07 RATE BASE GAS -RATE YEAR STARTING JULY 1, 2009

LAST REVIEW DATE July 17, 2009

	REVISED PROFORMA	AUTHORITY ADJUSTMENTS	TABLE I
UTILITY PLANT IN SERVICE	$619,712,844	($15,963,236)	$603,749,608
PLANT 2	0	0	0
LESS:CONS.WORK IN PROGRESS	0	0	0
LESS:ACCUM DEP AND AMORT	252,382,387	(1,803,007)	250,579,380
NET PLANT	367,330,457	(14,160,229)	353,170,228
PLUS:			
MATERIALS AND SUPPLIES	$57,638,580	(48,664)	57,589,916
WORKING CAPITAL	54,306,023	(21,024,989)	33,281,034
PREPAYMENTS	2,869,587	(2,559,431)	310,156
AMORTIZED CIAC	0	0	0
DEFERRED TANK PAINTING	0	0	0

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UNAMORTIZED DEFERRALS, NET	54,444,606	(10,030,261)	44,414,345
CONSERVATION EXPENDITURES	0	0	0
LESS:			
DEFERRED INCOME TAXES	$46,378,930	297,001	46,675,931
CUST.AD VANCES AND DEPOSITS	0	0	0
OTHER RESERVES	5,676,328	(376,862)	5,299,466
CIAC	0	0	0
DEFERRED GAIN ON LAND SALE	0	0	0
MISCELIANEOUS	0	0	0
MISCELIANEOUS	0	0	0
MISCELIANEOUS	0	0	0
RATE BASE	484,533,995	(47,743,713)	436,790,282
RETURN ON RATE BASE	10.09%	8.05%	8.05%
OPERATING INCOME	48,895,809	(13,745,500)	35,150,310

TABLETABULAR OR GRAPHIC MATERIAL SET FORTH AT THIS POINT IS NOT DISPLAYABLE

This Decision is adopted by the following Commissioners:

Anthony J. Palermino

Amalia Vazquez Bzdyra

Kevin M. DelGobbo

CERTIFICATE OF SERVICE

The foregoing is a true and correct copy of the Decision issued by the Department of Public Utility Control, State of Connecticut, and was forwarded by Certified Mail to all parties of record in this proceeding on the date indicated.

July 23, 2009

Kimberley J. Santopietro Executive Secretary Department of Public Utility Control

END OF DOCUMENT

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ATTACHMENT J

STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

North Shore Gas Company	:	
	:	**07-0241**
Proposed general increase in natural gas rates. (tariffs filed March 9, 2007)	:	
	:	
The Peoples Gas Light and Coke Company	:	**07-0242**
	:	
Proposed general increase in natural gas rates. (tariffs filed on March 9, 2007)	:	**Cons.**

ORDER

February 5, 2008

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STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

North Shore Gas Company	:	
	:	**07-0241**
Proposed general increase in natural gas rates. (tariffs filed March 9, 2007)	:	
	:	
The Peoples Gas Light and Coke Company	:	**07-0242**
	:	
Proposed general increase in natural gas rates. (tariffs filed on March 9, 2007)	:	**Cons.**

ORDER

By the Commission:

PROCEDURAL HISTORY

On March 9, 2007, North Shore Gas Company ("North Shore" or "NS") filed with the Illinois Commerce Commission ("Commission"), and pursuant to Section 9-201 of the Public Utilities Act (the "Act")[1], the following tariff sheets: ILL. C.C. No. 17, Original Title Sheet (cancelling ILL. C.C. No. 16 in its entirety) and ILL. C.C. No. 17, Original Sheet Nos. 1 through 130. This tariff filing embodied a proposed general increase in gas service rates, three new "tracker" Riders, and revisions of other terms and conditions of service. The tariff filing was accompanied by direct testimony, other exhibits, and other materials required under Parts 285 and 286 of Title 83 of the Illinois Administrative Code (the "Code"), 83 Ill. Admin. Code Parts 285 and 286.

On March 9, 2007, The Peoples Gas Light and Coke Company ("Peoples Gas" or "PGL") filed with the Commission, and pursuant to Section 9-201 of the Act, the following tariff sheets: ILL. C.C. No. 28, Original Title Sheet (cancelling ILL. C.C. No. 27 in its entirety) and ILL. C.C. No. 28, Original Sheet Nos. 1 through 143. This tariff filing embodied a proposed general increase in gas service rates, four new "tracker" Riders, and revisions of other terms and conditions of service. The tariff filing was accompanied by direct testimony, other exhibits, and other materials required under Parts 285 and 286.

Notice of the proposed tariff changes reflected in this rate filing was posted in North Shore's and Peoples Gas' (the "Utilities" or "Companies") business offices and published in secular newspapers of general circulation in the Utilities' respective service

[1] 220 ILCS 5/9-201.

areas, as evidenced by publishers' certificates, in accordance with the requirements of Section 9-201(a) of the Act and the provisions of 83 Ill. Admin. Code Part 255.

The Commission issued Suspension Orders as to North Shore's tariff filing on April 4, 2007, that suspended the tariffs to and including August 5, 2007, and further initiated Docket 07-0241. On July 25, 2007, the Commission issued a Resuspension Order, that suspended these tariffs to, and including, February 5, 2008.

The Commission issued Suspension Orders as to Peoples Gas' tariff filings on April 4, 2007, that suspended the tariffs to and including August 5, 2007, and initiated Docket 07-0242. On July 25, 2007, the Commission issued a Resuspension Order, that suspended these tariffs to, and including, February 5, 2008.

On April 23, 2007, Staff of the Commission ("Staff") filed a motion to consolidate Dockets 07-0241 and 07-0242, pursuant to 83 Ill. Admin. Code §200.600.

Pursuant to notice duly given in accordance with the law and the rules and regulations of the Commission, a pre-hearing conference was held in the two Dockets before duly authorized Administrative Law Judges ("ALJs") of the Commission, at its offices in Chicago, Illinois, on April 25, 2007, and April 27, 2007. More than ten days prior to April 25, 2007, notice of this status hearing had been provided by the Chief Clerk of the Commission to municipalities in the Utilities' service areas, in accordance with the requirements of Section 10-108 of the Act[2]. On April 25, 2007, at the status hearing, after addressing certain aspects of how consolidation would affect the conduct of these cases, the ALJs granted Staff's motion to consolidate.

Petitions to Intervene.

Petitions to Intervene were filed or appearances were entered on behalf of the Attorney General of the State of Illinois (the "Attorney General" or "AG"); the Citizens Utility Board ("CUB"); the City of Chicago (the "City") (collectively, CUB and the City are "CUB-City" or "City-CUB", their having used both terms in different filings) (collectively, the AG, CUB, and the City are "GCI" for "Governmental and Consumer Intervenors"); Constellation NewEnergy-Gas Division, LLC ("CNEG"); the Environmental Law and Policy Center ("ELPC"); the Illinois Industrial Energy Consumers ("IIEC"); Multiut Corporation ("Multiut"); Local Union No. 18007, United Workers Union of America, AFL-CIO (the "Local" or "UWUA"); Prairie Point Energy, LLC, d/b/a Nicor Advanced Energy, LLC ("NAE"); Retail Gas Suppliers ("RGS") an ad hoc group comprised of Dominion Retail Incorporated; Interstate Gas Supply; and U.S. Energy Savings Corporation; and Vanguard Energy Services, LLC ("Vanguard") (collectively, all of the foregoing parties are the "Intervenors").

Pre-Hearing Testimony.

On March 9, 2007, the Utilities filed their respective direct testimony together with their respective Part 285 filings. On June 5, 2007, Peoples Gas filed errata to its direct testimony and Part 285 submission.

[2] 220 ILCS 5/10-108.

On June 29, 2007, Staff and the Intervenors filed their respective direct testimony, except that Mr. Mierzwa did not submit direct testimony. RGS filed its direct testimony on July 2, 2007, and GCI filed their direct testimony on July 3, 2007.

On July 27, 2007, the Utilities filed the rebuttal testimonies of their witnesses.

On August 21, 2007, Staff and the Intervenors filed their respective rebuttal testimony, except that of Staff witness Rearden. On August 22, 2007 Staff moved for leave to file the rebuttal testimony of Staff witness Rearden *instanter*. On August 23, 2007, the ALJs issued a ruling granting Staff's Motion for Leave to File Rebuttal Testimony of Staff Witness David Rearden, *Instanter*.

On July 30, 2007, the ALJs granted Staff's Motion for Leave to File Supplemental Direct Testimony Instanter for its witness Kahle. On August 10, 2007, the Utilities filed supplemental rebuttal testimony of Mr. Fiorella to the supplemental direct testimony of Mr. Kahle.

On September 5, 2007 the Utilities filed the surrebuttal testimonies of their witnesses. On September 7, 2007, the Utilities filed a Second Errata, identifying corrections to attachments to their witness Amen's direct testimony. On September 10, 2007, the Utilities filed a Third Errata, identifying corrections to an attachment to the surrebuttal testimony of their witness Mr. Zack and deleting certain inadvertently repeated lines in the direct testimony of their witness Grace. And, on September 11, 2007, North Shore and Peoples Gas filed a Fourth Errata containing two corrections to its witness Ms. Grace's direct testimony and deleting a cross-reference in their witness Mr. Schott's surrebuttal testimony.

The Evidentiary Hearing.

The evidentiary hearing was held on September 10, 2007 through September 12, 2007, September 14, 2007, and September 17, 2007 at the offices of the Commission in Chicago, Illinois. At the evidentiary hearings, the Utilities, Staff, and the Intervenors, entered appearances and presented testimony. The following witnesses testified on behalf of the Utilities: Michael J. Adams, Director, Navigant Consulting, Inc.; Ronald J. Amen, Director, Navigant Consulting, Inc.; Lawrence T. Borgard, President and Chief Operating Officer, The Integrys Gas Group, and Vice Chairman of the Board and Chief Executive Officer, Peoples Gas and North Shore; Edward Doerk, Vice President, Gas Operations, Peoples Gas and North Shore; Russell A. Feingold, Managing Director, Navigant Consulting, Inc.; Salvatore Fiorella, Manager, State Regulatory Affairs, Peoples Gas (he retired from this position during these proceedings); Valerie H. Grace, Manager, Rates Department, Peoples Gas, and, subsequently, Manager, Regulatory Affairs; James C. Hoover, Director, Compensation, Integrys; Bradley A. Johnson, Treasurer, North Shore; Linda M. Kallas, Vice President, Financial Accounting Services, Peoples Gas; Brian M. Marozas, Coordinator, Trading Risk Management Department, Peoples Gas; Paul R. Moul, Managing Consultant, P. Moul & Associates; Joseph P. Phillips, Vice President, Information Technology, Integrys Business Support; Thomas L. Puracchio, Gas Storage Manager, Peoples Gas; Ilze Rukis, Manager, Alternative Resources, Wisconsin Public Service Corporation; James F. Schott, Vice President, Regulatory Affairs, Integrys Energy Group, Inc. and Peoples Gas; Eugene S. Takle,

Professor of Atmospheric Science and Agricultural Meteorology, Co-director, Regional Climate Modeling Laboratory, Iowa State University; Frank L. Volante, Operations Manager, North Shore; Thomas E. Zack, Vice President, Gas Supply, Integrys.

The following witnesses testified on behalf of Staff: Dennis L. Anderson, Senior Energy Engineer, Engineering Department, Energy Division; Janis Freetly, Senior Financial Analyst, Finance Department, Financial Analysis Division; Thomas L. Griffin, Accountant, Accounting Department, Financial Analysis Division; Cheri L. Harden, Rate Analyst, Rates Department, Financial Analysis Division; Dianna Hathhorn, Accountant, Accounting Department, Financial Analysis Division; Daniel G. Kahle, Accountant, Accounting Department, Financial Analysis Division; Sheena Kight-Garlisch, Senior Financial Analyst, Finance Department, Financial Analysis Division; Peter Lazare, Senior Economic Analyst, Rates Department, Financial Analysis Division; Eric Lounsberry, Supervisor, Gas Section, Engineering Department, Energy Division; Mike Luth, Analyst, Rates Department, Financial Analysis Division; Bonita A. Pearce, Accountant, Accounting Department, Financial Analysis Division; Dr. David Rearden, Senior Economist, Policy Program, Energy Division.

GCI's witnesses were Michael L. Brosch, Principal, Utilitech, Inc.; David J. Effron, Consultant; William L. Glahn, Principal and Owner, Piedmont Consulting, Inc., except that the City did not sponsor certain specified testimony of Mr. Brosch.

CUB-City's witnesses were Christopher C. Thomas, Director of Policy, CUB; Jerome D. Mierzwa, Principal and Vice President, Exeter Associates, Inc.

NAE's witness was Lisa Pishevar, General Manager, NAE.

CNEG's witnesses were John M. Oroni, Regional Sales Director, CNEG; and Lisa A. Rozumialski, Manager of Gas Operations, CNEG.

ELPC's witness was Charles Kubert, Senior Environmental Business Specialist, ELPC.

IIEC, VES and CNEG jointly sponsored the testimony of Dr. Alan Rosenberg, Consultant, Brubaker & Associates.

Multiut's witnesses were Nachshon Draiman, President, Multiut; Raquel Lavenda, Manager of Operations, Multiut.

RGS' witness was James L. Crist, President, Lumen Group

VES' witness was Neil Anderson, Partner, VES.

UWUA's witness was James Gennett, President, Local Union No. 18007.

All parties were given the opportunity to cross-examine witnesses.

During the evidentiary hearing, various witnesses on behalf of Staff and various parties submitted oral errata to their pre-filed testimony, as reflected in the transcripts. On September 20, 2007, the ALJs directed that Staff and the parties file revised versions of the affected pre-filed testimony reflecting the oral errata presented at the evidentiary hearing. Staff and the parties subsequently complied in these respects.

Certain additional materials were received into the record thereafter by order of the ALJs. On November 26 2007, the ALJs marked the record "Heard and Taken".

Rulings on Motions

On April 27, 2007, a Notice of Administrative Law Judges' Ruling established the procedural schedule for these now-consolidated Dockets. Thereafter, on May 9, 2007, the ALJs issued an Order for a Case Management Plan and Schedule in these dockets. Also on May 9, 2007, and after considering all of the parties' arguments, the ALJs entered a Protective Order for these Dockets

On August 13, 2007 the ALJs issued a ruling amending the case management order and confirming the date and time for the evidentiary hearing.

On September 5, 2007, the ALJs granted in part, and denied in part, the Utilities' Motion to strike portions of GCI witness Glahn's direct and rebuttal testimonies.

On September 17, 2007, the ALJs granted the AG's motion to strike a portion of the surrebuttal testimony of Mr. Schott. On September 18, 2007, Peoples Gas submitted its Second Revised surrebuttal testimony of Mr. Schott, reflecting the ALJs' ruling on the related motion to strike.

On September 25, 2007, the ALJs issued a ruling approving the Proposed Stipulation entered into by Peoples Gas, North Shore, CUB and City with respect to the testimony of Ms. Kallas.

On September 18, 2007, NAE filed a Motion to Correct Transcript. On September 27, 2007, UWUA filed a Motion to Correct Transcripts. On October 11, 2007, Staff filed a First Motion to Correct Transcripts. On October 15, 16, 17, 18, 19, and 22, 2007, the Utilities filed motions to correct the transcripts.

On December 26, 2007, the ALJs granted the various motions to correct the transcripts.

Post-Hearing Briefs.

On October 12, 2007, the Utilities, Staff, the AG, CUB, the City, ELPC, IIEC, Multiut, NAE, RGS, VES, and UWUA each filed an Initial Brief ("Init. Br.").Thereafter, on October 16, 2007, the Utilities filed a motion to correct their Initial Brief (to remove a superfluous paragraph). Also on October 16, 2007, Staff filed a Corrected Initial Brief (to correct the Appendices thereto).

On October 23, 2007, the Utilities, the AG, RGS, VES, City, CUB-City, ELPC, CUB, NAE, UWUA, IIEC, G, and Multiut each filed a Reply Brief ("Rep. Br."). Staff filed its Reply Brief on October 24, 2007. Also, on October 23, 2007, the Utilities submitted a draft Proposed Order.

On November 26, 2007, the ALJs issued their Proposed Order. On December 14, 2007, Briefs on Exceptions ("BOE") were filed by the Utilities, Staff, the AG, CUB, the City, ELPC, IIEC, Multiut, NAE, RGS, VES, and UWUA

On December 21, 2007, each of these same parties filed a Reply Brief on Exceptions ("RBOE").

This Order considers all of the positions and arguments set out in the exceptions briefs listed above.

I. INTRODUCTION

A. Summary of Standards

The Commission, in these proceedings, is presented with the Utilities' first general rate cases since 1995. In addressing the issues raised in these consolidated Dockets, and in our consideration of the extensive evidentiary record, the Commission is governed by a number of basic legal principles.

In contested rate case proceedings the Commission must establish rates that are just and reasonable, with the burden of proof on the utility to establish the justness and reasonableness of a proposed rate. 220 ILCS 5/9-201(c); Business and Professional People for the Public Interest v. Illinois Commerce Comm'n., 146 Ill. 2d 175, 208 (1991). The Act requires the Commission to establish rates which are just and reasonable for both the investors and the consumers. Citizens Utility Board v. Illinois Commerce Comm'n., 276 Ill.App.3d 730, 658 N.E.2d 1194 (1995).

While many of the presented issues are now uncontested, due to compromises among the parties, many disputed issues remain. Those disputes include the four new "tracker" Riders proposed by Peoples Gas and the three proposed by North Shore. The Commission will consider all of the uncontested and contested issues presented. We are mindful that all rulings and directives contained in this final Order must be within our jurisdiction, lawful and based exclusively on record evidence. 220 ILCS 5/10-103, 10-201(e)(iv); Business and Professional People for the Public Interest v. Illinois Commerce Comm'n, 136 Ill. 2d 192, 201, 227 (1989).

B. Nature of Operations

1. Peoples Gas

Peoples Gas is a local distribution company engaged in the business of transporting, purchasing, storing, distributing, and selling natural gas at retail to approximately 840,000 residential, commercial, and industrial customers within the City of Chicago. Peoples Gas Ex. LTB-1.0 at 4-5; Peoples Gas Ex. ED-1.0 at 3. This service territory covers an area of about 228 square miles and has a population of approximately three million people. Peoples Gas Ex. LTB-1.0 at 5. Peoples Gas employs approximately 1,540 people, virtually all within the City of Chicago. Id. at 5. Peoples Gas is a wholly owned subsidiary of Peoples Energy Corporation, which in turn is a wholly owned subsidiary of Integrys Energy Group, Inc. ("Integrys"). Id. at 5.

Peoples Gas' distribution system consists of approximately 4,025 miles of gas distribution mains. Peoples Gas Ex. ED-1.0 at 3. It owns approximately 425 miles of gas transmission lines. Id. The distribution system is most commonly operated at a pressure range of 0.25 to 25 pounds per square inch, while the transmission system operates at pressures up to 300 pounds per square inch or more. Id. Peoples Gas also owns a storage field, Manlove Field. Id.

The physical configuration of Peoples Gas' system is a dispersed/multiple city gate, integrated transmission/distribution and multi pressure-backed system. Id. It is designed to provide gas service to all customers entitled to be attached to the system, to deliver volumes of natural gas to all sales and transportation customers, and to meet the aggregate peak design day capacity requirements of all customers entitled to service on the peak day. Id. at 4. A gas utility system sized only to accommodate average gas demands would not be able to meet system peak demands. Id. at 4.

2. North Shore

North Shore is a local distribution company engaged in the business of transporting, purchasing, storing, distributing and selling natural gas at retail to approximately 158,000 residential, commercial, and industrial customers within fifty-four communities in Lake and Cook Counties, Illinois. NS Ex. LTB-1.0 at 4; NS Ex. ED-1.0 at 3. North Shore employs approximately 200 people, while sharing many administrative facilities owned by Peoples Gas. North Shore Ex. LTB-1.0 at 4. North Shore is a wholly owned subsidiary of Peoples Energy Corporation, which in turn is a wholly owned subsidiary of Integrys. Id. at 5.

North Shore's distribution system consists of approximately 2,270 miles of gas distribution mains. North Shore Ex. ED-1.0 at 3. North Shore owns approximately 95 miles of gas transmission lines. Id. Its distribution system is most commonly operated at a pressure of 45 pounds per square inch, while the transmission system operates at a pressure of 250 pounds per square inch. Id. While North Shore does not own any storage fields, it does purchase storage services from Peoples Gas, pursuant to a storage services agreement, approved by the Commission, and from two interstate pipelines. Id. In addition, North Shore owns a liquid propane production facility used for peaking purposes. Id.

The physical configuration of North Shore's system is a dispersed/multiple city-gate, integrated transmission/distribution and multi pressure-based system. Id. It is designed to provide gas service to all customers entitled to be attached to the system, to deliver volumes of natural gas to all sales and transportation customers, and to meet the aggregate peak design day capacity requirements of all customers entitled to service on the peak day. Id. at 4. A gas utility system sized only to accommodate average gas demands would not be able to meet system peak demands. Id.

C. Test Year

The Utilities each proposed their fiscal year 2006, i.e., the twelve months ending September 30, 2006, as their test year. Fiorella Dir., PGL-NS Ex. SF-1.0 at 5. The 2006 test year data were based on the Utilities' actual 2006 revenues, expenses, and rate base items, subject to appropriate adjustments. Id. at 6-7. No party contested the proposed test year, which was ordered by the Commission In re WPS Resources Corp., et al., Docket 06-0540, Appendix A, Condition of Approval No. 13 (Order Feb. 7, 2007).

II. RATE BASE

A. Overview

1. Peoples Gas

In its direct case, Peoples Gas proposed a rate base of $1,308,007,000, consisting of $1,500,600,000 of net plant ($2,434,914,000 of gross plant less $934,314,000 of Accumulated Provision for Depreciation and Amortization ("Depreciation Reserve"), plus $126,359,000 for three items increasing rate base, less $318,952,000 for items reducing rate base. *E.g.*, PGL Ex. SF-1.1 at Sched. B-1.

In the course of testimony, Peoples Gas either agreed with, or, in order to narrow the issues, accepted a number of rate base adjustments proposed by Staff and the GCI, resulting in a final rate base figure of $1,289,531,000. This figure consists of:

- $1,495,173,000 of net plant ($2,429,392,000 of Gross Utility Plant less $934,219,000 of Accumulated Provision for Depreciation and Amortization or "Depreciation Reserve");

- $126,359,000 for three additional items, i.e., Gas in Storage, Materials and Supplies, and Cash Working Capital; and

- $332,001,000 for reductions, mainly Accumulated Deferred Income Taxes. E.g., NS-PGL Ex. SF-4.1P.

The uncontested and contested issues relating to Peoples Gas rate base are being assessed in the following Sections (B) through (F) of this Part II of the Order.

2. North Shore

In its direct case, North Shore proposed a rate base of $197,107,000, consisting of $231,444,000 of net plant ($380,087,000 of gross plant less $148,643,000 of Depreciation Reserve), plus $10,922,000 for three items increasing rate base, less $45,259,000 for items reducing rate base. E.g., NS Ex. SF-1.1 at Sched. B-1.

In the course of further testimony, North Shore also agreed with, or for purposes of narrowing the issues, accepted a number of rate base adjustments proposed by Staff and GCI, that resulted in North Shore's final rate base figure of $193,577,000. That figure consists of:

- $229,779,000 of net plant ($378,350,000 of gross plant less $148,571,000 of Depreciation Reserve);

- $10,922,000 for three additional items, i.e., Gas in Storage, Materials and Supplies, and Cash Working Capital; and

- $47,124,000 for reductions, mainly Accumulated Deferred Income Taxes. *E.g.*, NS-PGL Ex. SF-4.1N.

The uncontested and contested issues relating to its rate base are discussed in the following Sections (B) through (F) of this Part II of the Order.

B. Uncontested Issues

1. Original Cost Determination as to Plant Balances as of 9/30/06

a) The Record

Staff and the Utilities agree as to the original cost findings regarding the Utilities' plant as of the end of the fiscal year 2006 (September 30, 2006). Staff recommended that the $2,327,990,000 original cost for Peoples Gas and the $369,442,000 original cost for North Shore of plant at September 30, 2006, reflected on the Utilities' Schedules B-1, Line 1, Column D, be unconditionally approved as the original cost of plant. In their surrebuttal testimony, the Utilities accepted Mr. Kahle's recommendation. NS-PGL Ex. LMK-3.0 at 5-6. Given Staff's recommendation regarding the original cost determination, Staff recommends the Commission's order state:

> It is further ordered that the $2,327,990,000 original cost for Peoples Gas and the $369,442,000 original cost for North Shore of plant at September 30, 2006, reflected on the Utilities Schedules B-1, Line 1, Column D, is unconditionally approved as the original cost of plant.

Staff Ex. 15.0 Corrected at 21-22.

b) Commission Analysis and Conclusion.

We accept Staff's recommendation to have the final order include an original cost determination pursuant to 83 Ill. Adm. Code 510 and Appendix A thereto, as follows:

> It is further ordered that the $2,327,999,000 original cost for Peoples Gas and the $369,442,000 original cost for North Shore of plant at September 30, 2006, as reflected on the Utilities' Schedules B-1, Line 1, column D, is unconditionally approved as the original cost of plant.

The Commission finds that this proposed language is reasonable, appropriate and agreed on. Therefore, it is approved.

2. *Pro Forma* Capital Additions

a) The Record

Peoples Gas and North Shore originally proposed *pro forma* adjustments, for post-test year capital additions reasonably expected to be placed in service no later than February 2008, in the gross amounts of $104,524,000 (net $95,464,000 after the applicable subtractions for Depreciation Reserve and ADIT) and $10,645,000 (net $9,899,000 after the applicable subtractions for Depreciation Reserve and ADIT), respectively. *E.g.*, PGL Ex. SF-1.0 at 18-19; PGL Ex. SF-1.1, Scheds. B-1, column [E], B-2, column [B], and B-2.1; NS Ex. SF-1.0 at 17-18; NS Ex. SF-1.1, Scheds. B-1, column [E], B-2, column [B], and B-2.1.

In his corrected rebuttal testimony, Staff witness Kahle proposed adjustments to the *pro forma* plant additions the Utilities had included in rate base. Mr. Kahle recommended the removal of costs which were only based upon 2007 capital budget

additions. Mr. Kahle found those budgeted costs to not be known and measurable in accordance with 83 Ill. Adm. Code 287.40. Staff Ex. 15.0, Schedules 15.2 N and P Corrected. As Mr. Kahle testified, the mere adoption of a budget is not evidence that a project is reasonably certain to occur as is required by Section 287.40. Staff Ex. 15.0 Corrected, at 15. After reviewing the Utilities' response to a data request, Mr. Kahle did allow *pro forma* capital additions that were supported by ten months of actual expenditures and two months of estimated expenditures. He found those amounts to be known and measurable.

In their surrebuttal testimony, the Utilities accepted Mr. Kahle's adjustments after Mr. Kahle in a data request response recognized and accepted Peoples Gas' cushion gas additions in the amount of $10.405 million. NS-PGL Ex. SF-4.0, at 5-6. Staff and the Utilities also agree on Staff's adjustment to Depreciation Expense. In his rebuttal testimony, Staff witness Kahle proposed adjustments to depreciation expense, the reserve for depreciation, and accumulated deferred income taxes related to the adjustments to pro forma plant additions. Staff Ex. 15.0, Schedules 15.2 N and P Corrected. In their surrebuttal testimony, the Utilities accepted Mr. Kahle's adjustments. NS-PGL Ex. SF-4.0 at 5-6.

The Utilities explain that they do not contest Staff's final revised figures for *pro forma* adjustments for capital additions, which consist of the amounts Staff's witness suggested in his rebuttal testimony (a reduction of $19,232,000 for Peoples Gas and $1,734,000 for North Shore (gross amounts)) plus an additional $10,405,000 of Peoples Gas' cushion gas additions he supported in a subsequent data request response (in evidence), i.e., a net $95,697,000 ($104,524,000 less $19,232,000 plus $10,405,000) as to Peoples Gas and a net $8,911,000 ($10,645,000 less $1,734,000) as to North Shore. Kahle Corr. Reb., Staff Ex. 15.0 at 14-16; NS-PGL Ex. SF-4.0 at 5-6; NS-PGL Ex. SF-4.2P, column [D]; NS-PGL Ex. SF-4.2N, column [D].

b) Commission Analysis and Conclusion

The Commission finds the Staff final revised proposal that the Utilities' *pro forma* adjustments for capital additions be a net $95,697,000 as to Peoples Gas and a net $8,911,000 as to North Shore to be unopposed by any party, reasonable and appropriate. Therefore, each of these amounts is approved.

3. Capitalized Lobbying Expenses

See Section III (B)(5)(d) of this Order, infra.

4. Capitalized City of Chicago Resurfacing Costs (PGL)

See Section III (B)(2)(c) of this Order, infra.

5. ADIT - Gas Cost Reconciliation

a) The Record

North Shore and Peoples Gas do not contest GCI's proposed adjustments to ADIT related to gas cost reconciliation. NS-PGL Ex. SF-2.0, 4:82-90, 5:109; PGL Ex. SF-2.2P, column [E]; NS Ex. SF-2.2N, column [D]. The proposed adjustments

increase ADIT, and thus reduce rate base, by the amounts of $5,748,000 as to Peoples Gas and $1,142,000 as to North Shore. GCI Ex. 2.0 at 14,16-17 and Sched. B-2.

b) Commission Analysis and Conclusion

The Commission finds that GCI's proposed adjustments to ADIT related to gas cost reconciliation as revised, which reduce Peoples Gas' rate base by $5,748,000 and North Shore's rate base by $1,142,000, are uncontested and reasonable. Therefore, these adjustments are each approved.

6. [ADIT] AMT - Gas Charge Settlement

a) The Record

The Utilities do not contest GCI's proposed adjustments to Alternative Minimum Taxes ("AMT"), and thus to ADIT. NS-PGL Ex. SF-2.0 at 4-5; PGL Ex. SF-2.2P, column [F]; NS Ex. SF-2.2N, column [E]. GCI witness Effron's proposed adjustments to AMT, and thus to ADIT, which are related to the gas charge settlement, increase ADIT, and thus reduce rate base, by $7,820,000 as to Peoples Gas and $773,000 as to North Shore. GCI Ex. 2.0 at 14-16 and Sched. B-2.

b) Commission Analysis and Conclusion

The Commission finds that GCI's proposed adjustments to Alternative Minimum Taxes, as revised, which increase ADIT and thus reduce Peoples Gas' rate base by $7,820,000 and increase ADIT and thus reduce North Shore's rate base by $773,000, are uncontested and reasonable. Therefore, these adjustments are approved in the amounts stated.

C. Plant

1. Capitalized Incentive Compensation

See Section III(C)(3)(b) of this Order, below.

2. Hub Services (PGL)

See Section V of this Order, below.

D. Reserve for Accumulated Depreciation and Amortization

1. GCI's Proposed Adjustments

a) North Shore and Peoples Gas

Peoples Gas and North Shore maintain that they each have correctly calculated the amounts for the Depreciation Reserves that are subtracted from gross plant when calculating their rate bases. In so doing, they started with the Depreciation Reserve amounts as of the end of the test year, fiscal year 2006, i.e., as of September 30, 2006, and then made the adjustments needed to reflect the impacts of their proposed adjustments to plant, including their *pro forma* adjustments for post-test year capital additions. PGL Ex. SF-1.0 at 9, 14-15 & 18; PGL Ex. SF-1.1, Sched. B-1, line 2, Sched. B-2, column [B], Sched. B-2.1, Sched. B-6; NS Ex. SF-1.0, at 9, 14-15 & 17- 18; NS Ex. SF-1.1, Sched. B-1, line 2, Sched. B-2, column [B], Sched. B-2.1, Sched. B-6.

b) Staff

Staff did not address this issue in its Initial Brief. On Reply Brief, however, Staff stated that:

> After further evaluating the positions advanced by the various parties in testimony and briefs, Staff withdraws its objections to Mr. Effron's adjustment. In particular, Staff no longer supports the position that Mr. Effron's adjustment violates 83 Ill. Adm. Code Section 287.40. The impact on the rate base of Peoples Gas is to increase the accumulated depreciation reserve $43,134,000 (GCI Ex. 5.1, Schedule B-1 Revised) and deferred income taxes $587,000 (GCI Ex. 5.1, Schedule B – 2 Revised). The impact on the rate base of North Shore Gas is to increase the accumulated depreciation reserve $5,721,000 (GCI Ex. 5.2, Schedule B-1 Revised) and deferred income taxes $15,000 (GCI Ex. 5.2, Schedule B – 2 Revised).

c) GCI Parties

(Both the AG and the City-CUB take similar positions on the issue).

The GCI point out that both Peoples Gas and North Shore proposed adjustments to rate base in order to recognize plant additions through September 30, 2007, or one year after the end of the test year. PGL Ex. SF-1.0 at 18, 19; NS Ex. SF-1.0 at 17. While the Utilities recognize the increase in accumulated depreciation directly related to the forecasted plant additions, the GCI observe that they do not recognize the growth in accumulated depreciation on embedded plant-in-service that will be taking place as the new plant additions are going into service. Id.

GCI witness Effron explained that, as future plant additions take place and increase the balance of gross plant, the accumulated reserve for depreciation will also continue to grow as a result of recording depreciation expense on total plant-in-service. Thus, the net plant-in-service included in rate base will not increase by an amount equal to future additions. According to Mr. Effron, when growth in the balance of the accumulated reserve for depreciation is taken into account, as it should be, the effect of growth in rate base due to plant additions is mitigated significantly. Id. at 7-8.

The GCI contend that the Utilities have failed to consider and include this necessary offset to the revenue requirement effect of the post-test year additions to plant. The record shows, they argue, that in the 12 months ended September 30, 2006, Peoples recorded $48,664,000 of depreciation and amortization expense on its jurisdictional plant-in-service. Id. Further, from September 30, 2006 to September 30, 2007 (the period covered by the proposed additions to plant) the balance of accumulated depreciation and amortization can be expected to increase by more than $48 million as a result of recording depreciation expense on plant that was in service during the test year. GCI Ex. 2.0 at 6. Because the accumulated reserve for depreciation is deducted from plant in service in the determination of rate base, this increase in the depreciation reserve will reduce rate base by more than $48 million, and consequently reduce the revenue requirement. GCI witness Effron noted that while the amounts are proportionally smaller for North Shore, the principle is the same: The

growth in the accumulated reserve for depreciation will provide a substantial offset to the growth in rate base resulting from plant additions. Id. at 7.

The AG notes the Utilities to assert that the cases relied on by Mr. Effron in testimony fail to support his proposed adjustment for accumulated depreciation. PGL-NS Ex. SF-4.0 at 8. In particular, the Utilities claim that the Orders in CILCO, Docket No. 02-0837, and AmerenCIPS and AmerenUE, Docket Nos. 02-0798, 03-0008 & 03-0009 (consol.), are not relevant to this proceeding based on the facts and circumstances for reason that "those cases pertained to utilities which had no increase in net plant." Id. The GCI argue, however, that these are only two of the cases that Mr. Effron considered.

For their part, the GCI refer the Commission to the Illinois Power case, Docket No. 01-0432, and AmerenCIPS and AmerenUE. In both matters, GCI observe, plant-in-service was growing but, as is the case in this docket with Peoples Gas and North Shore, such growth was found to be offset by growth in the reserve for depreciation. For example, they note, in AmerenCIPS and AmerenUE the Commission found "that UE's proposed additions to plant-in-service should be included in rate base" only "to the extent that they exceed increased accumulated depreciation." Docket Nos. 02-0798, 03-0008 & 03-0009 (consol.), Order (October 22, 2003). The Commission further concluded that this balanced treatment of plant additions and accumulated depreciation more accurately matches the costs and revenues that may be expected for the period during which the rates are in place. Id.

The GCI further contend that a review of the Commission's decisions in the CILCO case and the AmerenCIPS and AmerenUE cases also support Mr. Effron's position that adjustments to include post-test year plant additions in rate base should be offset by the known and measurable growth in the balance of the accumulated reserve for depreciation that will occur as plant is being added. GCI observe the Utilities to claim that these cases involved circumstances when there was no increase in net plant over time. PGL-NS SF-4.0 at 8. In the GCI's view, however, the argument that the circumstances in these cases are irrelevant to the instant docket is, in effect, to argue that if there is no increase in net plant over time, then it is appropriate to recognize post test year growth in depreciation reserve, but if the net plant is growing by $1 per year, then it would be inappropriate to recognize post-test year growth in the depreciation reserve as an offset to post-test year plant additions. A reasonable reading of the Commission's decisions in these dockets, the GCI maintain, supports Mr. Effron's balanced adjustment to recognize post-test year growth in the Utilities' depreciation reserve.

GCI summarize that, to allow the Company to reflect adjustments to rate base for post-test year plant additions without recognizing the attendant growth in the accumulated reserve for depreciation will result in a mismatch of rate base items and a significant distortion of the Utilities' rate bases during the period of time rates set in this case will be in effect. Accordingly, they argue, North Shore's pro forma test year rate base should be reduced by $5,721,000. GCI Ex. 5.2, Schedule B. And, Peoples Gas' pro forma test year rate base should be reduced by $43,134,000 to recognize post-test

year growth in the accumulated reserve for depreciation that will accompany the growth in plant-in-service from post-test year additions to plant-in-service. Id.

d) North Shore / Peoples Gas Response

The Utilities contend that the Commission should reject the adjustments to the Depreciation Reserves proposed by GCI witness Effron. GCI Ex. 2.0 at 5-12; GCI Ex. 5.0 at 3-6. Noting Mr. Effron to assert that his proposed adjustments somehow are justified by the Utilities' proposed *pro forma* adjustments for post-test year capital additions, the Utilities point out that he does not, and cannot, claim that the Utilities have incorrectly calculated the impacts of those adjustments on the Depreciation Reserves. Instead, Utilities argue, Mr. Effron inappropriately and incorrectly seeks to use those adjustments as an excuse to add another year of depreciation to the Depreciation Reserve related to existing plant as of the test year, and not to the depreciation applicable to the *pro forma* adjustments for post-test year capital additions for which the Utilities already correctly have accounted. NS-PGL Ex. SF-2.0 at 9-1; NS-PGL Ex. SF-4.0 at 8-9. Utilities note Staff's witness to agree that Mr. Effron's proposed adjustments are inappropriate and incorrect for that reason, *i.e*., the proposed adjustments switch test years for the Depreciation Reserve values for existing plant as of the test year. Staff Ex. 15.0.

The proposal also is unfair, Utilities assert, because it does not move forward to a 2007 value, rather than a test year value, other items which would increase the Utilities' revenue requirements. NS-PGL Ex. SF-2.0 at 10. Indeed, the Utilities contend, Mr. Effron's claim that the ADIT value likely would increase in 2007 and "there is no reason to believe that the other components [of rate base besides net plant and ADIT] would change materially from the test year to 2007", misses the point about inappropriately and unfairly deviating from test year principles. GCI Ex. 5.0 at 3-4.

Mr. Effron's proposed adjustment, the Utilities argue, should further be rejected for failure to meet the criteria for *pro forma* adjustments. According to the Utilities, it does not meet the "known and measurable" criteria of 83 Ill. Adm. Code § 287.40, as Staff's witness also pointed out. Staff Ex. 15.0 at 17. The Utilities maintain that the proposal is based on attrition, and contrary to the attrition and inflation language of 83 Ill. Adm. Code § 287.40, the same that Mr. Effron himself invoked when opposing the Utilities' proposed *pro forma* adjustments for inflation in non-payroll expenses, and which the Utilities later withdrew. GCI Ex. 2.0 at 26-27 (mistakenly citing the predecessor provision of 83 Ill. Adm. Code § 287.40 in Part 285 of the Commission's rules prior to the 2003 amendments).

The Utilities observe that the Commission rejected adjustments like those that Mr. Effron proposes In re Commonwealth Edison Co., Dkt. 05-0597; Order at 12-15, (July 26, 2006) and In re Commonwealth Edison Co., Dkt. 01-0423; Interim Order at 41-44 (April 1, 2002) (carried forward to final Order of March 28, 2003). While Mr. Effron would claim that his proposal finds support in other Commission orders, the Utilities assert that the facts of the instant proceeding are more like those of the two cases they rely on and not the ones that Mr. Effron cites to (where the utilities had no increase in net plant). *See also* NS-PGL Init. Br. at 20; NS-PGL Ex. SF-2.0 at 10; NS-PGL Ex. 4.0 at 8. To be sure, the Utilities argue, their circumstances here are not the same as those

of the utilities in any of the cases cited to by the GCI. Peoples Gas' and North Shore's net plant in service balances, they assert, have not been decreasing over time, but have been increasing. According to the Utilities, the record, i.e., Schedules B-5 and B-6 in PGL Ex. SF-1.1 and NS Ex. SF-1.1 and Tr. 117-118, provides uncontradicted evidence of the Utilities' increasing net plant balances.

Peoples Gas and North Shore explain that they are using a historical test year. And, the Utilities maintain that they have provided supporting documentation to parties with respect to their *pro forma* adjustments for post-test year capital additions (amounts of approximately $96 million for Peoples Gas and $9 million for North Shore, reflecting the correct deductions for the Depreciation Reserves and ADIT). *E.g.*, NS-PGL Ex. SF-2.0 at 8-9; NS Ex. SF-1.1, Sched. B-2; PGL Ex. SF-1.1, Sched. B-2. As a result, the Utilities' *pro forma* adjustments for post-test year capital additions are uncontested. NS-PGL Init. Br. at 16-17. Yet, it seems to the Utilities that GCI would seek to use this as a pretext for their proposed adjustments to the Depreciation Reserves. The Utilities maintain that they correctly dispute the proposal of GCI witness Effron to add another year of depreciation to the Depreciation Reserves; a proposal that is applicable to existing plant, and not related to the plant involved in the *pro forma* adjustments. They note too, that Staff's witness agreed that Mr. Effron's proposed adjustments that, in effect, change the test year for existing plant, were inappropriate and incorrect

The Utilities emphasize that the decisions on point with the instant proceeding appear in Commonwealth Edison Co., Docket No. 05-0597, Order (July 26, 2006) and Commonwealth Edison Co., Docket No. 01-0423, Interim Order (April 1, 2002) (incorporated in final Order, March 28, 2003). Yet, they observe, these are decisions that the AG and City-CUB neglect to address in their Briefs. In those cases, the Utilities point out, the Commission rejected Mr. Effron's proposed adjustments to Depreciation Reserves that are virtually the same as he now proposes in this proceeding, and in situations that are factually similar to the situations of Peoples Gas and North Shore. According to the Utilities, the facts set out in the cases cited by the AG and City-CUB are much different.

In Docket 05-0597, Utilities point out, the AG unsuccessfully argued that decisions in the same IP, AmerenCIPS, AmerenCILCO, and AmerenUE cases, were relevant to the ComEd case. There ComEd argued, as do the Utilities here, that those cases factually were not on point. Order at 13-15, Docket No. 05-0597. The Commission agreed with ComEd and rejected the AG's proposed adjustment to the Depreciation Reserve, stating in relevant part that :

> At issue here is the AG's proposed adjustment to the accumulated reserve for depreciation in order to make the pro forma balance consistent with the pro forma plant in service included in rate base. ComEd contends that the proposal presented by the AG violates Section 287.40 and test year rate making principles. The AG's proposed adjustment does not correlate to any pro forma 2005 capital additions or any plant adjustment proposed by any of the parties. Instead, the AG's proposal merely takes one part of the rate base and moves it one additional year into the future. ComEd argues that the Commission rules and test year ratemaking principles prohibit

> such an adjustment. The Commission concurs with ComEd as to this issue. Further, the Commission finds the cases presented by the AG to be inapplicable and without merit. The Commission agrees with ComEd's assertion that the effect of the AG's proposed adjustment would be to inappropriately bring the test year into the future for accumulated depreciation. The Commission rejects the AG's proposed adjustment. Order at 15, Docket 05-0597 (July 26, 2006).

No different here, Utilities argue, the GCI's proposed adjustments to the Depreciation Reserves do not correlate to any *pro forma* plant additions or to any plant adjustment proposed by any of the parties. Instead, and in a summary fashion, GCI's proposed adjustments take one part of rate base and move it into the future. Based on the foregoing, the Utilities contend that GCI's proposed adjustments to the Depreciation Reserve are not warranted, violate test year rate making principles, and are not appropriate under the *pro forma* adjustments rule, 83 Il Admin. Code § 287.40.

Further still, the Utilities would note that Mr. Effron's proposal miscalculates the Utilities' costs of removal, because it does not comport with how the Utilities account for these costs. According to the Utilities, he erroneously proposes to deduct amounts for costs of removal from the Depreciation Reserves when, instead, they should be added to depreciation expenses, and this would increase the revenue requirements. And, Utilities add that his figures are wrong. NS-PGL Ex. SF-2.0 at 11-12; NS-PGL Ex. SF-4.0 at 9-10 (also noting that the Commission has accepted the Utilities' accounting for costs of removal over several decades).

e) Commission Analysis and Conclusion

All parties agree that this issue has been previously addressed by the Commission. All parties largely agree that the facts differ from one case to another. All parties should agree that Commission action brings certainty to a situation and settles expectations. This is another way of saying that unless there are clear and distinguishable reasons for deciding a case differently, the Commission will follow in line with precedent. To do otherwise risks a charge of arbitrary and capricious action.

There is much debate as to which of the decided cases are most reflective of the instant situation. Having reviewed the evidence and the parties' arguments, we find that the facts at hand most closely resemble the situation that we most recently considered in Docket 05-0597 (that concerns Commonwealth Edison Company). In that proceeding, then AG witness Effron proposed to increase through the end of 2005, the entire depreciation pertaining to all plant that went into service prior to and in the 2004 test year. Order at 12, Docket 05-0597. The proposal of GCI witness Effron is essentially the same in this case.

Here, as in Docket 05-0597, the Utilities made depreciation adjustments for post-test year plant that comprises its pro forma additions. Here, as in Docket 05-0597, the Utilities argue that the proposed adjustment is one-sided and unfair. Here, as in Docket 05-0597, the Utilities argue that the proposal presented by the intervening party violates Section 287.40 and test year rate-making principles. Here, as in Docket 05-0597, the Utilities argue that the proposed adjustment merely takes one part of rate base and

moves it one additional year into the future. Here, as in Docket 05-0597, the same Orders entered in earlier dockets are being asserted by the intervening parties in support of their position.

In our conclusion for Docket 05-0597 the Commission determined that the same cases that the GCI parties rely on here, were inapplicable and without merit. Order at 15, Docket 05-0597. We further agreed with the assertion (made in this proceeding) that the effect of the proposed adjustment would be to "inappropriately bring the test year into the future for accumulated depreciation. Id. We observed too, that the proposed adjustment does not correlate to any pro forma capital additions or any plant adjustment proposed by any party. In the end, the Commission rejected the AG's adjustment in Docket 05-0597.

In our view, and under our analysis, the outcome of the 05-0597 proceeding is controlling on the dispute at hand. Indeed, we are shown nothing as would have us depart from the decision that the Commission set out in that matter. Staff's changed position on Reply Brief is insufficient in these premises. For their part, the GCI take little or no account of the facts, circumstances or findings in Docket 05-0597. Consistent with our prior and controlling decision on the issue, and for the same reasons, we here reject the GCI's proposed adjustment. While Staff and the GCI take exception with our reliance on the disposition of this issue in the ComEd orders, they make no attempt to distinguish the facts in that proceeding from the facts at hand. Thus, we are unable to lawfully deviate from that conclusion. Moreover, Staff effectively admits that additional record analysis is needed to allow for consideration of the GCI's proposed adjustment. This (and the arguments that the Utilities set out in reply to the exceptions), convinces the Commission that, on the evidence presented, our decision is right.

2. Derivative Adjustments

Other than GCI's proposed adjustments to the Utilities' Depreciation Reserves, discussed in Section II (D)(1) of this Order, Staff and Intervenors have not proposed any independent adjustments to the Depreciation Reserves as such. Accordingly, the Commission, as to the Depreciation Reserves, need only make derivative calculations reflecting the approved adjustments to plant in rate base.

E. Cash Working Capital

Cash working capital ("CWC") is the amount of cash a company requires to finance its day-to-day operations. PGL-NS Ex. MJA-1.0 at 3. To understand why that amount of cash is included in rate base, where it earns a return for the utility, CWC can be conceptualized as a cash advance from investors. That is, insofar as the flow of cash in and out of the utility's coffers is imperfectly balanced, and the utility requires ready funds to pay expenses as they become due, investors finance the shortfall. To calculate whether such shortfall indeed exists, and to determine its size and duration (which vary over the course of a year) for ratemaking purposes, regulators and utilities employ recognized accounting principles and methodologies.

The principle method used is the lead-lag study. It focuses on expense leads (the time intervals between a utility's assumption of responsibility for various expenses (typically, when a product or service is received) and the actual payment of those

expenses) and revenue lags (the time interval between acquiring the rights to revenues and the actual receipt of revenues). Approved categories of leads and lags are quantified, weighted, summed and compared. The difference is CWC (positive or negative[3]).

Disputes can arise with respect to the type of lead-lag study used and the identification and treatment of the expenses and revenues included. Initially, the Utilities calculated CWC using the *net* lag methodology[4]. Id. Subsequently, though, the Utilities acceded to Staff's preference for the *gross* lag methodology[5], stating that the two methodologies, when properly applied, produce essentially equivalent results. PGL-NS Ex. MJA-2.0 at 4.

However, the Utilities and Staff disagree regarding treatment of certain inputs for the gross lag analysis. First, Staff proposes to include capitalized payroll and payroll-related expenses in CWC calculations, and the Utilities object. Second, the Utilities would use pass-through taxes to calculate expense lead times, while Staff would not. Third, the Utilities would treat all Taxes Other Than Income Taxes alike, but Staff would split off real estate taxes for separate treatment. The Commission addresses each disputed issue in the following subsections of this Order.

Prior to service of the ALJ's Proposed Order, the Utilities' calculations yielded a CWC allowance of approximately $30.9 million for PGL and ($1.1 million) for North Shore. PGL-NS Ex's. MJA-1.1. Staff's adjustments would have decreased Peoples Gas's and North Shore's CWC allowances to, approximately, $16.6 million and ($1.7 million), respectively (assuming no other adjustments to the Utilities' requested revenues and identified expenses). Staff Init. Br., App. A, p. 8 & App. B, p. 9.

After service of the Proposed Order, the Utilities requested "correction" of what they perceived to be mathematical errors in the appendices attached to the Proposed Order, as well as inconsistencies between the text of the Proposed Order and the appendices[6]. The requested revisions would alter the Utilities' approved CWC and other elements in its revenue requirement calculations (as they appeared in the Proposed Order).

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[3] When CWC is negative, there is a surplus, rather than a shortfall, in day-to-day funds. A subtraction is made from rate base to account for negative CWC, as Staff and the Utilities propose here for North Shore. Staff Ex. 15.0 at 14.

[4] In a net lag study, all leads are added (in days), as are all lags. The totals are netted against each other, then the net revenue lag (if any) is divided by 365 days to determine a daily CWC factor. Adjusted yearly cash expenses are multiplied by that factor to quantify CWC (the amount of cash to include in rate base).

[5] In a gross lag study, the sum of revenue lags is divided by 365 days to establish a daily CWC factor, which is multiplied by the utility's adjusted test year revenues. (Adjustments remove non-cash items, such as depreciation and uncollectibles, that are unavailable to pay expenses.) Similarly, each category of expense lead is also divided by 365 days and the resulting CWC factor is multiplied by test year expenses. The revenue and expense working capital requirements are then summed to determine CWC for rate base.

[6] The Utilities first raised these issues in a motion, which was denied on procedural grounds, then restated the issues on exceptions.

In particular, the Utilities maintain that the appendices incorrectly included amounts for depreciation and amortization in CWC calculations. PGL-NS BOE at 7. Staff agrees that those amounts should be removed, to correct an inadvertent omission of the necessary deduction. Staff RBOE at 2. Staff proposes an approach for calculating the deductions, *id.*, at 3 and App's A & B, which we find reasonable and hereby approve.

Also on exceptions, Staff recommended a clarification of a mislabeled item in the Appendices to the Proposed Order. As Staff states, the item should be labeled "Operating Expenses." Staff BOE at 8.

1. Capitalized Payroll and Payroll-Related Expenses

Staff recommends that we include "capitalized payroll, pensions and benefits in the CWC requirement calculation because these items reflect cash outlays of the [Utilities'] normal day-to-day operations." Staff Init. Br. at 7. "[W]hen the company incurs a cost like payroll, cash is required regardless of whether the cost is expensed or capitalized." Id. Staff emphasizes that we approved the use of capitalized payroll for calculating CWC in the recent Ameren consolidated rate cases[7].

The Utilities respond that Staff is improperly injecting capitalized costs into a CWC calculation that should be limited to operating expenses, with the result that the Utilities' CWC requirements are understated. PGL-NS Ex. MJA-3.0 at 11. "Capital expenditures are not included in the analysis because such costs were considered elsewhere in rate base." Id. at 13. Furthermore, the Utilities argue, even if it were appropriate to use capitalized costs to compute CWC, there would have to be a corresponding revenue stream to cover those costs, but Staff has not included that revenue stream in its CWC analysis. Id. Moreover, the Utilities maintain, Staff "has selectively chosen which capitalized costs to include" in its CWC determination, while ignoring others that similarly entail cash outlays by the Utilities. Id.

Commission Analysis and Conclusion

In the Ameren rate cases, the Commission adopted Staff's recommendation that capitalized payroll costs be included in the CWC calculations. In doing so, we emphasized that Ameren had not included in rate base "any payroll costs going forward from the test year." Ameren, at 36. With the absence of capitalized payroll costs in rate base, Ameren would not realize recovery on such costs. Consequently, we were willing to include capitalized payroll costs in Ameren's CWC computation, both because there would be no double recovery on them (i.e., they would not appear in rate base twice) and because fulfilling payroll commitments was a day-to-day operational obligation of the utility. In these proceedings, however, the pertinent payroll costs appear to be accounted for in the Utilities' rate bases. Staff does not claim otherwise. It follows that the precedential rationale for including a *capitalized* cost in an analysis concerning *operational expenses* is missing.

[7] AmerenCILCO, AmerenCIPS, and AmerenIP, Docket Nos. 06-0070, 06-0071 & 06-0072 (Cons.) ("Ameren"), Order November 21, 2006, at 36.

The question, then, is whether another rationale for Staff's position exists. Staff states that "[l]ike cash outlays for items that are expensed, capitalized items must also be paid." Staff Ex. 15.0 at 8. Moreover, Staff emphasizes, "they are paid with the same lead time" as capitalized payroll costs. Id. Restating Staff's proposition, because capitalized payroll items behave like expensed payroll items, they belong in the CWC calculation. The Commission does not agree. The relevant accounting rules and test year mechanics are clear – capitalized items enter rate base and operating expenses do not. PGL-NS Ex. 3.0 at 14. Perhaps the real essence of Staff's argument is that payroll-related costs should not be included in rate base at all (other than as part of the CWC calculation). If so, that argument is unexpressed and certainly undeveloped in this dispute. In any event, the fact that an item requires a cash outlay does not mean it belongs in the CWC determination. Virtually everything a utility purchases involves cash outlay, but the purchase is either capitalized or expensed, not both. Finally - and this point is not part of our decision-making on this issue - it is not apparent to the Commission how reducing CWC, while double-counting items in rate base, would reduce customers' bills.

On exceptions, Staff recommends an approach for removing capitalized payroll-related costs from previous CWC calculations in these dockets. Staff RBOE at 3-7 & App's. A & B. The Utilities also propose a method. PGL-NS BOE at 8-9 & Except's. 3 & 4. These parties do not disagree with respect to certain components of the process for removing capitalized expenses (e.g., the use of "Pensions and Benefits" and "Payroll and Withholding" for this purpose). They do apparently differ regarding "Inter-Company Billings." Staff avers that the amounts relating to such billings "have nothing to do with capitalized payroll-related expenses." Staff RBOE at 6. Staff's detailed explanation on this point appears correct. Accordingly, the Commission concludes that Staff's proposed method for removing capitalized payroll-related costs from previous CWC calculations in these dockets should be adopted in all respects. Insofar as Staff's proposal differs from the Utilities', it provides the better approach.

2. Pass-Through Taxes

Staff and the Utilities dispute whether pass-through taxes should be included within the "Taxes Other Than Income Taxes" component of the CWC calculation. The Utilities aver that pass-through taxes have an "indisputable impact" on their cash flow and, therefore, should be taken into account when determining the expense *lead time* of Taxes Other Than Income Taxes. PGL-NS Init. Br. at 27. However, the Utilities claim, it is inappropriate to include the expense *dollars* represented by such taxes in CWC calculations, "because the Companies do not bear ultimate responsibility for pass-through taxes." Id. In other words, the Utilities assert that the timing of pass-through tax expense is pertinent to CWC, but the dollar-amount is not. Thus, $224 million in taxes, including $206 million in pass-through taxes, were used by the Utilities to calculate lead *days*, Staff Ex. 15.0 at 11, but only $17.6 million in taxes[8] (presumably

[8] Since the Utilities do not "bear ultimate responsibility" for *any* taxes, the Commission does not understand why any taxes were included under the Utilities' methodology.

not pass-through taxes) were included to calculate *cash flow* for determining Taxes Other Than Income Taxes.

Staff asserts that pass-through taxes should be excluded in the CWC calculation because they "do not impact the financing of day to day operations. [They] are collected by the [Utilities] from customers and…passed on to the appropriate taxing body." Staff Init. Br. at 9. If pass-through taxes truly impact the Utilities' cash flows, Staff contends, then their dollar amounts would belong in the CWC analysis. "Since they do not, the pass-through taxes were excluded in the [Utilities'] final calculation [of cash flow] and should have been excluded in calculating lead days." Id. at 10. "The effect of including over $206 million of 'pass-through' taxes in the lead days calculation [but not in the dollar calculation] unfairly skews the weight of the lead days toward the shorter lead times and greater amounts of the 'pass-through' taxes." Id. at 9.

Commission Analysis and Conclusion

The parties appear to have reversed the positions they took with regard to inclusion of capitalized payroll items in the CWC analysis. That is, the Utilities, having opposed recognition of the practical impact of payroll-related cash outlays on cash flow, now insist that the practical cash flow impact of tax collection and payment should be recognized in CWC computations. Staff, after emphasizing the real effect of payroll-related items on cash flow, now dismisses the effect of pass-through taxes, even though collected tax revenues enter and leave the Utilities' accounts. The explicit and implicit rationales underlying this role reversal are unpersuasive, although they do (perhaps inadvertently) point the way to an appropriate resolution of this dispute.

To begin, the Commission agrees with the Utilities that tax obligations affect cash flow. The Utilities collect money from ratepayers to meet governmental obligations, then satisfy those obligations with later payments[9]. PGL-NS Ex. 3.0 at 20. But it is irrelevant that the Utilities do not "bear ultimate responsibility" for the taxes they collect. CWC concerns day-to-day financing, not where cash outlays ultimately go. For financing purposes, tax receipts are no different than customer receipts. The Utilities either have the cash flow (including the flow generated by tax recovery) to pay expenses or they need temporary investor financing (CWC). Thus, in the previous subsection of this Order, our exclusion of capitalized payroll items from the CWC analysis was not due to an absence of day-to-day financial impact (indeed, such impact exists), but due to their inclusion in rate base through capitalization. That is not true of taxes. Accordingly, if pass-through taxes are used to determine lead times, the Commission perceives no reason to exclude tax expense dollars from the lead-lag calculation. The dollar-weighting of tax expense leads, for CWC purposes, should reflect all of the Taxes Other Than Income Taxes used by the Utilities to compute lead times[10].

[9] The gas revenue tax is an exception. The Utilities calculate a negative lead for that tax. PGL-NS Ex. MJA-1.0 at 14.

[10] Staff had initially envisioned an alternative result here - that pass-through taxes would be removed from CWC calculations because they "are not recovered through base rates." Staff Ex. 15.0 at 11. In Staff's briefs, however, that proposal seemed to transmute into a recommendation that pass-through taxes remain in CWC, but with real estate taxes accorded separate treatment. Staff Init. Br. at 10. (We address

On exceptions, the Utilities request that we correct a purported error in the Proposed Order whereby the dollar amounts of pass-through taxes were included in the expense lead calculations but not in the Proposed Order's revenue lag calculations. PGL-NS BOE at 9-10. Staff responds that there is no error because pass-through taxes do not create a revenue lag. "There can never be a revenue lag for pass-through taxes because there is no 'date customers receive service' related to receiving pass-through taxes." Staff RBOE at 8. Furthermore, Staff argues, the record contains no evidence of an actual revenue lag associated with pass-through taxes (or any of them). Id. The Utilities instead use the revenue lag for the regulated gas services they provide to customers (49.44 days). Staff avers that the Commission "cannot assume the lag days for revenue would be the same for pass-through taxes without analysis." Id.

Staff's latter argument is incorrect under the Utilities' chosen methodology, which assumes revenue lag for CWC purposes is *always* the monthly interval between delivering gas to the customer and having access to customer payments after they are deposited in the bank. PGL-NS MJA-1.0 at 5. That is, the Utilities bill monthly (and, by measuring from the middle of the service month, calculate that they can access the associated receipts about 49 days later), which, for CWC purposes, they treat as the sole way they obtain customer funds, whether for taxes or other items.

Regarding Staff's first argument – that there is no revenue lag for pass-through taxes – Staff's apparent concern is that pass-through taxes provide no service to the customer and involve no product or service costs (other than tax collection costs, which are presumably recovered as O&M expenses). Moreover, several of the taxes are paid quarterly or annually, which raises the question of how, in common sense, they can have a revenue lag. That said, however, the Utilities still must obtain revenue to remit to the taxing bodies, and the only revenue collection mechanism in the record, with its attendant revenue lag, is the monthly bill. Consequently, while the Commission would welcome additional analysis, as Staff suggests, addressing the movement of pass-through taxes in and out of the Utilities' accounts for CWC purposes, we do not have that analysis here. For now, we will include pass-through taxes in the revenue portion of the gross lag study approved in these dockets.

3. Real Estate Taxes

Real estate taxes have a significantly longer expense lead time than the other taxes included within Taxes Other Than Income Taxes. As figured by the Utilities, the weighted lead time for all Taxes Other Than Income Taxes (including real estate taxes) is 43.67 days, PGL-NS Ex. 1.0 at 13, while the specific lead time for real estate taxes alone is slightly above 380 days. Id. at 16. Consequently, Staff argues that real estate taxes "should be treated separately so the true effect of real estate tax lead is

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that proposal in the next subsection of this Order.) In any case, Staff's multiple citations to our prior Orders, Staff Ex. 15.0 at 12-13, demonstrate its awareness that we have *included* pass-through taxes in prior CWC analyses.

considered." Staff Ex. 15.0 at 12. Staff stresses that property taxes received separate treatment in several prior dockets[11]. Id. at 12-13.

In a manner that the Commission finds not entirely clear, Staff also proposes separate treatment for real estate taxes as a kind of remedy for the Utilities' decision (addressed in the immediately preceding subsection of this Order) to use pass-through taxes in computing expense lead times, but not in computations involving expense lead dollars. "To correct for the [Utilities'] skewing of lead days toward the heavily weighted pass-through taxes…real estate taxes should be treated separately for the effect of lead days for real estate taxes in the CWC requirement calculation." Staff Rep. Br. at 4. Per this proposal, pass-through taxes would remain in the Taxes Other Than Income Taxes lead time calculation, but not in the cash flow analysis, and property taxes would be handled similarly but separately.

The Utilities rejoin that "[s]eparating real estate taxes from other non-income taxes, and thereby failing to dollar weight them, inappropriately affords real estate taxes disproportionate impact on the CWC calculation as compared to all other dollar-weighted, non-income taxes." PGL-NS Init. Br. at 26. Furthermore, the Utilities say, Staff inconsistently recommends distinct treatment for the long lead time associated with property taxes, but not the relatively shorter lead times (when compared to the tax group as a whole) of other non-income taxes. Id.

Commission Analysis and Conclusion

It appears that property taxes appeared on a separate line in the CWC calculations in prior cited cases because the other taxes in Taxes Other Than Income Taxes were treated separately as well. In these proceedings, the Utilities package all of those taxes in a "basket," and maintain that, because of dollar-weighting, the CWC result is no different than if each tax were analyzed separately. PGL-NS Ex. 3.0 at 18. By separating real estate taxes, the Utilities contend, and not dollar-weighting them with the others, Staff reduces CWC[12]. Staff's concern, however, is that the particularly long lead time for property taxes will be "diluted" by inclusion with the other taxes. Staff Rep. Br. at 5.

The Commission will not approve separate treatment for real estate taxes. Although they have the longest lead time among the pertinent taxes, others also have relatively long leads – City of Chicago Use Tax (236 days) and State of Illinois Corporate Franchise Tax (185 days). PGL-NS Ex. 1.0 at 15-16. While we agree with Staff that we do have the discretion to treat atypical tax leads differently, we do not see a meritorious rationale for doing so here. We prefer the consistency of the Utilities' approach, and dollar-weighting mitigates the impact of a longer lead on the cluster of shorter leads among Taxes Other Than Income Taxes. Therefore, when computing

[11] Our research shows that the treatment of property taxes was not in dispute in any of those proceedings.

[12] The Commission cannot be sure of the claimed magnitude of the reductions. Utilities' witness Adams purports to derive the amount of Staff's Taxes Other Than Income Taxes from Staff's filings, but the figures for Staff's Taxes Other Than Income Taxes in MJA-2.1, p. 4, are not identical to the figures in Staff witness Kahle's exhibits. Staff Ex. 15.0, Ex. 15.0, Sch.s 15.1 N & 15.1 P, p. 2 (in each schedule), line 18 (in each schedule).

both the lead times and cash flow impacts of pass-through taxes, as required in the preceding subsection of this Order, *all* such taxes should be utilized as a single "basket" in this instance[13].

In all other (undisputed) respects, the Utilities' calculation of CWC is approved.

F. Gas in Storage

1. Working Capital

a) North Shore/Peoples Gas

To ensure that they will have gas sufficient to fill their customers' needs, the Utilities purchase gas and inject it into storage fields. For accounting purposes, the Utilities initially record all such stored gas as working inventory. Later, based on studies performed to determine the percentage of stored gas that should be considered "working" or "top" gas and the percentage that should be considered "cushion" or "base" gas, the Utilities reclassify appropriate quantities of top gas and record it as base gas. PGL-NS Ex.-TEZ 3.0 at 37.

In accordance with the Uniform System of Accounts, the Utilities explain that stored gas classified as top gas is included in rate base as working capital and recorded as Gas in Storage. They further explain that gas which is classified as base gas is included in rate base as part of net plant. *See, e.g.,* PGL Ex. SF-1.0 at 11, NS Ex. SF-1.0 at 11; 83 Ill. Admin. Code 505.1170, 505.1641.

Based on 13 month averages as of the end of the test year, fiscal year 2006, *i.e.,* as of September 30, 2006, Peoples Gas' working capital allowance in rate base for Gas in Storage is $86,667,000, and North Shore's is $10,507,000. *E.g.*, PGL Ex. SF-1.0 at 15-16; PGL Ex. SF-1.1, Sched. B-1, line 6 and Sched. B-8.1, column [M]; NS Ex. SF-1.0 at 15; NS Ex. SF-1.1, Sched. B-1, line 6 and Sched. B-8.1, column [M].

b) Staff

Staff recommends a reduction of $13,549,797 to Peoples Gas' requested $86,667,000 working capital allowance associated with gas in storage due to Peoples Gas maintaining 6,896,183 Mcf of storage gas in excess of normal levels. Staff Ex. 23.0 at 6-7. Staff also recommends a reduction of $1,422,772 to North Shore's requested $10,507,000 working capital allowance associated with gas in storage due to North Shore maintaining 866,543 Mcf of storage gas in excess of normal levels. Id. at 15-16.

Staff maintains that the gas storage volumes, that the Utilities would include in the test year, greatly exceeds their respective historical storage volumes. Id. at 6 and 15. According to Staff, Peoples Gas' requested test year gas volume (Fiscal Year 2006: October 1, 2005 to September 30, 2006) was on average more than 4 Bcf[14] higher than

[13] To provide clarity for future proceedings, we note that we are neither *requiring* "basket" treatment of Taxes Other Than Income Taxes nor prohibiting line item treatment of those taxes. Rather, we are merely approving the Utilities' "basket" treatment as an acceptable option, with the *requirement* that all such taxes belong in the basket.

[14] Bcf is equal to 1,000,000 Mcf or 1,000,000,000 cubic feet.

the prior two fiscal years (Fiscal 2005 and 2004) and more than 10 Bcf higher than Fiscal Years 2003 and 2002. Staff Ex. 11.0 at 7-8 and Staff Ex. 11.0, Schedule 11.3P. North Shore's requested test year gas storage volume was about 900,000 Mcf higher than the storage volume from the prior 4 fiscal years. Id. at 25.

Staff argues that the revenue requirement determined in the instant proceeding should be based upon normal conditions. Id. Staff notes that the information provided by the Utilities in response to Staff data request ENG 7.05 allowed for a comparison of the number of heating degree days assumed for the test year against the actual number of degree days for fiscal years 2002 through 2006. This data, Staff explains, showed that none of the historical fiscal years provided a match for the heating degree days the Utilities assumed as part of the normalized test year. Id. at. 9 and 17-18. As such, Staff concluded that the Utilities' requested amounts were not based on normal conditions and this contributed to their maintaining a larger than normal volume of storage gas. Id. at 8 and 17.

Staff states that it further requested the Utilities to provide the storage volumes they had assumed would occur if a normal year occurred in the test year. Id. at 9 and 18. Staff explains that it used this information (provided in response to Staff data request ENG 7.10), to calculate the volume of gas the Utilities would have maintained in the test year under normal conditions; Staff then used that normalized volume to determine the appropriate working capital allowance for gas in storage. Id. and Staff Ex. 23.0, Schedules 23.2P and 23.2N.

According to Staff, this calculation showed that Peoples Gas needed to reduce its gas in storage volume by 6,896,183 Mcf, and this is the basis for Staff's recommended adjustment of $13,549,797. Staff Ex. 23.0 at 9 and Staff Ex. 23.0, Schedule 23.1P. Staff states that it performed the same calculations for North Shore Gas' storage volumes, and concluded that North Shore needed to reduce its gas in storage volume by 866,543 Mcf and this is the basis for Staff's recommended adjustment of $1,422,772. Staff Ex. 23.0 at 18 and Staff Ex. 23.0, Schedule 23.1N.

Staff's review is included in the rebuttal testimony of Eric Lounsberry, and it reflects that the Utilities' requested working capital allowance for their gas in storage amounts involved storage volumes that were significantly higher than historical levels and that the test year volumes were overstated due to the warmer than normal weather during the test year. The Utilities did not dispute Staff's conclusions in their surrebuttal testimonies. Therefore, Staff's recommended reduction to working capital allowance for gas in storage for both Utilities, which was based upon the Utilities' expected test year storage activity under normal weather conditions, should be accepted.

Staff observes the Utilities to have explained that their excess gas in storage is a result of warmer than normal weather conditions. NS-PGL Ex. TZ-2.0 at 74. As such, the Utilities pointed out that the winter of 2006[15] was the fifth warmest on record, and that January 2006 was the warmest January on record. Id. On these bases, Staff

[15] The Utilities' test year of October 1, 2005, through September 30, 2006, (Fiscal 2006) included the winter of 2006.

observes the Utilities to conclude that these warmer than normal temperatures contributed to the increased test year storage volumes maintained by both Utilities. Id.

Staff points out that, as even Peoples Gas admits, its excess test year inventory is due to warmer than normal weather conditions in the test year. On record, Staff asserts, it demonstrated that these test year volumes are significantly higher than the historic gas storage volumes for both of the Utilities. As such, Staff contends it properly normalized the gas storage volumes requested by the Utilities to determine a normalized working capital allowance for gas in storage.

Staff notes too that the Utilities' arguments only address inventory volumes at Manlove field and do not consider leased storage. According to Staff, however, the analysis performed by its witness considered three leased storage services in addition to Manlove field for Peoples Gas (Staff Ex. 23.0, Schedule 23.2P) and considered two leased storage services in addition to Manlove field for North Shore. Staff Ex. 23.0, Schedule 23.2P. Thus, Staff asserts, there is more involved here than just Manlove storage.

In setting rates, Staff observes that the Commission has historically viewed larger than normal values for gas in storage as not meeting the legal just and reasonable standard. For example, Staff notes that in the Order for Dockets 02-0798, 03-0008, 03-0009 (October 22, 2003), the Commission accepted Staff's arguments that the storage inventory levels were excessive and reduced the working capital allowances associated with gas in storage. Id. at 22. Here too, Staff argues, the Commission should accept Staff's recommended reductions to working capital allowance for gas storage

c) North Shore/Peoples Gas Response

The Utilities oppose Staff's recommendation that the Commission reduce their Gas in Storage simply because there was more gas in storage at the end of the test year than at the end of certain prior years. The Utilities explain that the difference in circumstance was primarily due to weather. According to the Utilities, the exceptionally warm winter in 2006 caused them to pull less gas out of storage to meet customer needs than they might otherwise have had to withdraw. NS-PGL Ex. TEZ-2.0, 74:1636-46. The Utilities also point out that Staff itself concedes that a utility does not necessarily cycle all of its working gas, depending on the winter weather. D. Anderson, Tr. at 473:11-18.

The Utilities further explain that Staff's proposed adjustment to working inventory should have no net impact on total rate base. In accordance with applicable regulatory requirements, the Utilities assert, they are allowed to include the cost of all gas stored underground in their rate base, e.g., PGL Ex. SF-1.1, Sched. B-1, lines 1, 6; 83 Ill. Admin. Code §§ 505.1170, 505.1641. And, they argue, this is so regardless of whether that gas is classified as top gas or base gas. Thus, the Commission's acceptance of Staff's proposed disallowance relative to the Utilities' working capital allowance for Gas in Storage would mean, at most, that the value of the Utilities' base gas would have to be adjusted upward by an equal amount.

d) Commission Analysis and Conclusion

As an initial matter, the Commission notes that neither the arguments of the Utilities nor those of Staff, are models of clarity in dealing with the issue at hand. The Utilities appear to suggest that they are entitled to include in rate base the level of natural gas actually in storage during the test year, period. They fixate on the fact that the natural gas actually exists and that gas in storage is either top gas or base gas. And, the Utilities assert that they are allowed to include both top gas and base gas in rate base and, therefore, all gas in storage should be included in rate base.

In the Commission's view, it is true that natural gas can serve the function of either top gas or base gas and that by definition the gas in storage is either one or the other. The Utilities' idea that natural gas can simply be converted from top gas to base and back again, is not a view that the Commission shares. As the Commission understands it, base gas is the quantity of gas in storage needed for a storage field to operate properly; that is, allow the top gas to be injected and withdrawn to meet the needs of utility customers. While the quantity of gas that is classified as base gas is subject to revision in some circumstances, it does not fluctuate as the Companies seem to suggest.

It appears that Staff has done the better job in focusing on the proper question before the Commission, i.e., whether the Utilities had more top gas in storage than was necessary to meet the needs of utility customers during the test year. The evidence of record appears to support the theory that due to warmer than normal weather during the test year, the Utilities did not withdraw as much top gas from storage as they would during a normal or colder than normal year. This does not indicate that the Utilities did anything wrong. It does explain; however, why they had more top gas in storage during the test year than is necessary to meet the needs of their customers. Contrary to what the Utilities suggest, they are not necessarily entitled to include in rate base all gas in storage.

In proposing its adjustment, Staff looked to the difference between the quantities of underground gas on hand at the end of the test year as opposed to other years. The Utilities contend that the test year was unusual. But, this is precisely why a historical review is necessary and we expect that Staff took the weather differences from this data into account when assessing whether the volume that is set out as working inventory in the test year is fairly representative of the volumes going forward. According to Staff, it is not.

In conclusion, the Commission finds that Staff has demonstrated that the Utilities had more top gas in storage than necessary to meet their customer needs. Thus we approve Staff's proposed downward adjustments to the working capital requirements of Peoples Gas and North Shore for gas in storage. Nothing in the Utility's BOE persuades us otherwise.

2. Accounts Payable

a) Peoples Gas/North Shore

The Utilities maintain that they correctly did not include any offset for accounts payable in their Gas in Storage figures. They dispute Staff's claim that there should be deductions of $26,727,000 from Peoples Gas' Gas in Storage in rate base and $6,098,000 from North Shore's Gas in Storage in rate base, based on the theory that vendors financed these purchases and, therefore the storage gas included in each rate base should be reduced by the related amounts of accounts payable "because the Companies should not earn a return on the storage gas until it has been funded by investors." Kahle Corr. Supplemental Dir., Staff Ex. 3.0 Supp., 2:37-42.

According to the Utilities, their witness Fiorella provided uncontradicted testimony showing that the Utilities paid for the Gas in Storage in rate base, and that there are no accounts payable for the Gas in Storage in rate base because, under the applicable standard contract, the Utilities paid for this storage gas within no more 16 days from the receipt of the invoices from the vendors. NS-PGL Ex. 3.0 at 2. He stated quite simply that: "The item in question, gas storage inventory balances, is based on historical costs, which have been paid for and financed by the Utilities." Id. at 4:71-73. It is already established, the Utilities note, that their Gas in Storage in rate base is based on 13 month averages as of the end of the test year, fiscal year 2006, i.e., as of September 30, 2006. *E.g.* ,PGL Ex. SF-1.0 at 15-16; PGL Ex. SF-1.1, Sched. B-1, line 6, and Sched. B-8.1, column [M]; NS Ex. SF-1.0 at 15; NS Ex. SF-1.1, Sched. B-1, line 6, and Sched. B-8.1, column [M]. Hence, the Utilities argue, the accounts payable relating to the Gas in Storage in rate base were paid, at least, over a year ago, and in each instance they were paid no more 16 days from when the Utilities received the invoices from the vendors. According to Staff's own witness, "the Companies should not earn a return on the storage gas until it has been funded by investors." Staff Ex. 3.0 Supp., 2. This is just the situation here, the Utilities assert, in that the Gas in Storage in rate base is fully funded by investors -- it has been for over a year.

The Utilities note that Staff's rebuttal testimony does not deny that the accounts payable related to the Gas in Storage in rate base have been paid. Instead, Staff's witness offers the revised theory that his proposed adjustments should be approved because Gas in Storage purchased after the test year will be "financed" by vendors. Staff Ex. 15.0 at 18-19. Even at that, the Utilities argue, Staff's witness does not, and cannot deny, that such "financing" consists of nothing more than the fact that the Utilities pay vendors' invoices for storage gas in no more than 16 days. He does not and cannot deny that the Utilities must, and do, pay those invoices. The thrust of Staff's position, the Utilities observe, is to unreasonably deny the Utilities recovery of and on substantial amounts of their actual historical investments in the Gas in Storage in rate base simply because they do not instantly pay for gas in storage.

Staff's witness refers to five Commission Orders that he contends support his position, including the Utilities' 1995 rate cases but, as he acknowledged, all five involved future test years. Staff Ex. 15.0 at 20. Staff's position, and the application of those five Orders to the instant proceedings, which involve an historical test year, not a future test year, does not fit the facts, is inappropriate, and also unfairly fails to take into

account regulatory lag, i.e., the delay between the large cost under-recovery experienced by the Utilities during the test year through the period when the rates will go into effect beginning in 2008. NS-PGL Ex. SF-3.0 at 3-4; NS-PGL Ex. 4.0 at 7 8. Staff's proposed adjustments to impose accounts payable offsets against the Gas in Storage in rate base lack merit and should not be approved.

b) Staff

Staff witness Kahle proposed adjustments to the Gas in Storage the Utilities had included in rate base. According to Mr. Kahle, his adjustments removed costs which were not financed by investors and were not supported by actual expenditures. These costs were supported by accounts payable, and as such, were funded by vendors. Staff contends that the Utilities should not earn a return on that Gas in Storage. Staff Ex. 15.0 Corrected, at 17-18; Id. Schedules 15.3 N and P at 1.

Staff observes Utilities witness Fiorella to have agreed that, to the extent that the Utilities have not paid for a good or service that has been received, an accounts payable exists on the Utilities' books, and the vendor has provided temporary financing. While Mr. Fiorella went on to state that no adjustment should be made because the account payable no longer existed; he did not contend that the accounts payable did not exist during the test year. North Shore/Peoples Gas Ex. SF-3.0 at 2-3. In fact, the amount of the Gas in Storage adjustment was calculated using accounts payable balances supplied by the Utilities in a data request response. Staff Ex. 15.0, Schedules 15.3 N and P, at 2.

Staff notes Mr. Fiorella to have stated that the accounts payable no longer existed at the end of the test year. In response, however, Mr. Kahle made the point that as certain accounts payable are paid; other accounts payable are created in the normal gas purchasing cycle such that a portion of Gas in Storage would continue to be financed by vendors through accounts payable, Staff Ex. 15.0, at 19, and the Utilities at no time offered that any other items that might have expired since the end of the test year should be excluded; such as, the Gas in Storage that was reported on the Utilities' Schedule B-1 which may have been withdrawn and consumed by ratepayers since the end of the test year. Staff Ex. 15.0 Corrected at 19.

Mr. Fiorella made the additional argument that no adjustment related to accounts payable should be made to Gas in Storage because the Utilities had filed a historic test year. PGL-NS Ex. SF-3.0 at 3; Staff claims, however, that the accounts payable for gas in storage should received the same treatment as accounts payable for materials and supplies. Staff Ex. 15.0 Corrected at 18-19.

As further support for its adjustment, Staff notes that in the Utilities' previous rate cases, i.e., Dockets 95-0031 and 95-0032; Orders at 5-6 (November 8, 1995), the Commission accepted an adjustment to reduce Gas in Storage by associated accounts payable. Further, Staff observes that the Commission applied the same treatment in its Orders for Docket 04-0779 (Nicor Gas Company); Docket 93-0183, (Illinois Power Company); and Docket 95-0219 (Northern Illinois Gas Company). Staff Ex. 15.0 at 20, Corrected.

The Utilities' argument over an historical test year verses a future test year does nothing, in Staff's view, to show that accounts payable will not continue to exist. Further, Staff considers the Utilities' reference to regulatory lag to be misplaced. In the end, Staff recommends that the Commission adopt its adjustment for accounts payable associated with storage gas as presented on Schedules 15.3 N & P by reducing Gas in Storage included in rate base for the related accounts payable by $6,098,000 for North Shore and by $26,727,000 for Peoples Gas.

c) North Shore / Peoples Gas Response

The Utilities assert that Staff's proposed adjustments to impose accounts payable offsets against the Gas in Storage in rate base are unjustified and should be rejected. The Gas in Storage in rate base, they argue, is fully funded by investors and has been for over a year. The Utilities paid for the Gas in Storage in rate base, and there are no accounts payable for the Gas in Storage in rate base. Under the applicable standard contract, the Utilities paid for this storage gas within 16 days from the receipt of the invoices from the vendors. NS-PGL Ex. 3.0 at 2. Further, the Utilities' Gas in Storage in rate base is based on thirteen month averages as of the end of the test year, fiscal year 2006, i.e., as of September 30, 2006. *E.g.,* PGL Ex. SF-1.0 at 15-16; PGL Ex. SF-1.1, Sched. B-1, line 6, and Sched. B-8.1, column [M]; NS Ex. SF-1.0 at 15; NS Ex. SF-1.1, Sched. B-1, line 6, and Sched. B-8.1, column [M]. Hence, the accounts payable relating to the Gas in Storage in rate base were paid over a year ago, and in each instance they were paid no more than 16 days from when the Utilities received the invoices from the vendors.

According to the Utilities, Staff does not dispute that the Utilities paid in full for the Gas in Storage included in their rate bases over a year ago and, they assert, the evidence of that fact is uncontradicted. Further, the Utilities note that Staff's own witness agreed that storage gas should be included in rate base if it has been funded by the Utilities. *See* Staff Ex. 3.0 Supp at 2.

Instead, the Utilities note Staff's rebuttal testimony and its Initial Brief makes much of the fact that the amounts of Gas in Storage in the Utilities' rate bases include amounts as of the end of the test year, i.e., as of September 30, 2006. On this basis, the Utilities observe Staff to conclude this to mean that a portion of the Gas in Storage balances was "financed by vendors" as of September 30, 2006. Staff Init. Br. at 14-15. The Utilities consider Staff's brief to be a bit imprecise. According to the Utilities, the amounts in rate base were calculated using the averages of balances in the thirteen months ending on September 30, 2006. PGL Ex. SF-1.1, Sched. B-1, line 6, Sched. B-8.1, column [M]; NS Ex. SF-1.1, Sched. B-1, line 6, Sched. B-8.1, column [M].

The Utilities argue that Staff's point, i.e., that there were accounts payable for Gas in Storage as of September 30, 2006, does not mean that the Utilities did not pay for the Gas in Storage in rate base. Although the thirteen-month average included the balance for the month ending on September 30, 2006, and there were accounts payable as of that date, the Utilities paid off the last amounts owed for a fraction of the Gas in Storage in rate base no later than October 16, 2006. The Utilities maintain that this is no reason to disallow any of the costs of the Gas in Storage in rate base.

Staff also overlooks the net balances for storage gas as of September 30, 2006. Peoples Gas' storage gas balance as of September 30, 2006, was $127,746,000 (PGL Ex. SF-1.1, Sched. B-8.1, line 13, column [M]), while the accounts payable as of that date were $26,652,159 (Staff Ex. 15.0, Sched. 15.3 P, p. 2, line 13), yielding a net balance of $101,093,841. Peoples Gas only included $86,667,000 of Gas in Storage in its rate base. Thus, the net balance as of September 30, 2006, is lower than the amount in Peoples Gas' rate base. The same is true as to North Shore. *See* NS Ex. SF-1.1, Sched. B-8.1, line 13, column [M]; Staff Ex. 15.0, Sched. 15.3 N, p. 2, line 13. Thus, for this additional reason, the accounts payable balances as of September 30, 2006, do not warrant any disallowance.

The Utilities note Staff's Initial Brief to fall back on its witness' theory that, after the test year, the Utilities continued and will continue to use and buy storage gas, and this means that vendors will continue to "finance" storage gas, i.e., they will send invoices that are paid by the Utilities within a maximum of 16 days. *See* Staff Init. Br. at 15. According to the Utilities, this also is no reason to disallow any of the costs of the Gas in Storage in rate base, for which the Utilities paid in full.

Staff makes the point that some of the Gas in Storage included in rate base may have been withdrawn and consumed by customers since the end of the test year. Staff Init. Br. at 15. However, as noted above, the Gas in Storage amounts in the rate bases are based on thirteen-month averages, so they already reflect the test year's injections and withdrawals.

Staff also argues that their proposed adjustments are supported by the treatment of materials and supplies balances. Staff Init. Br. at 15. The Utilities, in their filings, in order to narrow the likely contested issues, chose not to contest materials and supplies accounts payable offsets, but that is not a reason to adopt the same as to Gas in Storage. Also, as Staff's exhibits show, for much of the year, the Utilities owe zero accounts payable for Gas in Storage. Staff Ex. 15.0, Sched. 15.3 P at 2., lines 4-7, Sched. 15.3 N at 2, lines 3-7. The facts that, some of the time, the Utilities owe amounts for Gas in Storage, and that they pay the invoices for that storage gas within no more than 16 days, do not justify disallowances.

Finally, the Utilities observe Staff to cite other rate cases where the Commission approved accounts payable offsets to Gas in Storage balances. Staff Init. Br. at 15-16. According to the Utilities, however, these cases do not support Staff's proposed adjustment. Unlike the situation in these proceedings, the cases on which Staff relies each involve future test years where the utilities have not yet paid for the Gas in Storage in their rate bases, and because the use of a future test year mitigates the regulatory lag of an historical test year rate case. NS-PGL Ex. SF-3.0 at 3-4; NS-PGL Ex. SF-4.0 at 7-8. The Utilities' Gas in Storage in their rate bases should be approved in full, not offset by accounts payable to deny them recovery on amounts they in fact have paid.

d) Commission Analysis and Conclusion

The Commission considers Staff's proposed adjustments to impose accounts payable offsets against the Gas in Storage in rate base and the Utilities' challenges to that proposal.

The Utilities maintain that while vendors arguably "finance" the storage gas, they pay vendors' invoices in no more than 16 days. This is the main thrust of their argument. In Staff's view, however, there is value to the Utilities during the term of those 16 days. Indeed, Staff considers the assertion that accounts payable are paid within sixteen days to confirm rather than disprove, that the accounts payable exist. Regardless of when the accounts payable were paid, Staff goes on to tell us, the fact remains that costs for gas in storage are continually being incurred and that there is a continual level of gas in storage that is supported by accounts payable. And, Staff asserts, the Utilities should not earn a return on that gas in storage.

We note too that what Staff asks be done in this instance is nothing new. In other words, there are a number of other cases where we made similar adjustments. The Utilities' attempts to distinguish these earlier situations from the present case are not convincing.

Staff bases the amount of its adjustment on accounts payable figures provided by the Utilities in a data request response. Staff Ex. 15.0 Corrected, Schedules 15.3 N and P at 2. While a more detailed discussion of Staff's methodology would have been useful, we do not see the Utilities to present any challenges on Staff's calculation.

Accordingly, the Commission adopts Staff's adjustment for accounts payable associated with storage gas as presented on Schedules 15.3 N & P by reducing Gas in Storage included in rate base for the related accounts payable by $6,098,000 for North Shore and by $26,727,000 for Peoples Gas. Nothing in the Utilities' BOE persuades us differently in these premises.

G. OPEB Liabilities and Pension Asset/Liability

1. North Shore / Peoples Gas

Peoples Gas, in calculating its rate base, included neither its net pension asset of $110,000,000 nor its net OPEB liability of $31,570,000 (gross amount $55,563,000). *See, e.g.*, NS-PGL Ex. LMK-2.0 2REV at 12-13; Staff Init. Br., App. A Corr., at 6, column (k).

North Shore, in calculating its rate base, included neither its net pension liability of $24,000 nor its net OPEB liability of $4,074,000 (gross amount $7,094,000). *See, e.g.*, NS-PGL Ex. LMK-2.0 2REV at 12-13; Staff Init. Br., App. B Corr., at 5, column (h). Thus, if the Utilities had included their respective pension asset/liability and OPEB liabilities, which symmetrical treatment would require, NS-PGL Ex. LMK-2.0 2REV at 13; NS-PGL Ex. LMK-3.0 at 3, then Peoples Gas' rate base would have increased by a net $78,430,000, and North Shore's rate base would have decreased by a net $4,098,000. During the test year, fiscal year 2006, Peoples Gas and North Shore point out that they contributed $15,278,614 and $1,862,247, respectively, to the pension plan. NS-PGL Ex. LMK-3.0 at 3.

2. The GCI Parties

(The AG and the City-CUB hold to the same position on this issue).

The GCI explain that Peoples Gas and North Shore accrue liabilities for Other Post Employment Benefits ("OPEB") pursuant to Statement of Financial Accounting Standards 106 ("FAS 106"). According to GCI witness David Effron, the Utilities have accrued OPEB liabilities to the extent that the cumulative accruals are greater than the actual cash disbursements for the post retirement benefits. GCI Ex. 2.0 at 11-12. As such, the accrued liabilities represent the expenses accrued in excess of actual payments for OPEB. Id. As of September 30, 2006, i.e., the end of the test year, the accrued liability for OPEB was $7,094,000 for North Shore and $55,653,000 for Peoples. Id.

CGI witness Effron testified that each Company's test year rate base should reflect the OPEB deduction. GCI Ex. 2.0 at 13. Likewise, the AG points out, Staff witness Bonita Pearce concurred with Mr. Effron's adjustment, and she noted that ratepayers have supplied funds for future obligations, such that a source of cost-free capital has been provided to the utility which should be recognized in the revenue requirement as a reduction from rate base. Staff Ex. 14.0 at 21-22.

City-CUB maintain that the Utilities' failure to deduct their accrued OPEB liability from rate base violates established Commission policy. In the Order for Docket 95-0219 (Northern Illinois Gas Company),they note, the Commission held that as long as the utility continues to control the ratepayer-supplied OPEB funds, the OPEB deduction should be recognized in the determination of rate base. Docket 95-0219, Order at 10. In that same utility's subsequent rate case, the Commission again applied this policy in determining rate base, and deducted $97,393,000 of "Retirement Benefits, Net" (comprised of the accrued OPEB liability) from the utility's plant in service. Id. at 31. And, in Docket Nos. 06-0070, et al. (cons.) (AmerenCILCO, AmerenCIPS, AmerenIP), the Commission confirmed this precedent, by finding that the accrued OPEB liability should be removed from rate base.

In this case, the GCI point out, the Utilities have failed to present any reason for the Commission to deviate from its established policy. Accordingly, they argue, the Commission should reflect a rate base deduction of $7,094,000 ($4,074,000 net of related deferred taxes) for the North Shore accrued OPEB liability and a rate base deduction of $55,653,000 ($31,570,000 net of related deferred taxes) for the Peoples Gas accrued OPEB liability in the determination of the Utilities' rate bases. *See* GCI Ex. 2.0 at 13.

3. Staff

Other Post Employment Benefits ("OPEB") liability, Staff explains, is the employer's obligation for post retirement benefits generally, such as health care, life insurance, tuition assistance and other types of post retirement benefits outside of a pension plan. In the instant proceeding, Staff asserts, the accrued OPEB liability represents a cost-free source of capital and should be treated for ratemaking purposes as a reduction of rate base. Staff Exhibit 14.0, at 21.

Staff witness Bonita Pearce agrees with GCI witness Effron's adjustment to reduce utility rate base for the accrued OPEB liability. Staff Exhibit 14.0 at 20 – 24. Additionally, Ms. Pearce disagrees with Utilities' witness Kallas regarding her assertion

that if utility rate base were reduced by accrued OPEB liability, the pension asset/liability should also be reflected in rate base.

For ratemaking purposes, Staff explains, a rate base reduction of the accrued liability associated with OPEB is appropriate to the extent that the test year obligation is unfunded or partially funded. The accrued liability represents the aggregate OPEB costs recognized in the income statement which has not been paid to a third party. Ratepayers have supplied funds for future obligations; therefore, a source of cost free capital has been provided to the utility which should be recognized in the revenue requirement as a reduction from rate base. Id. at 21-22.

Staff views Ms. Kallas' assertion as inconsistent with ratemaking theory because the pension asset of Peoples and the pension liability of North Shore do not represent elements of rate base that should impact the return to shareholders. The respective asset/liability was not created with funds supplied by shareholders, and for this reason, shareholders do not need to earn a return on such amounts. Staff Exhibit 14.0, at. 22.

Staff notes that the treatment of OPEB liability was considered in the most recent Northern Illinois Gas Company rate proceeding, Docket 04-0779 and in the Ameren Utilities' latest request for an increase in delivery service tariffs ("DST"), Dockets 06-0070, 06-0071, and 06-0072, consolidated (AmerenCILCO, AmerenCIPS, AmerenIP) Order at 27, (November 21, 2006), as fully cited by Mr. Effron in direct testimony. GCI Exhibit 1.0, at 13. In these cases, Staff informs, the Commission found that the OPEB liability should be treated as a reduction of utility rate base. Staff Exhibit 14.0 at 23.

Further, Staff notes that the Commission addressed the issue of pension asset treatment in Docket 04-0779, and in Docket 95-0219. In both instances, the Commission found that the pension asset was created by ratepayer-supplied funds, not by shareholder-supplied funds. As such, it concluded that ratepayers should not be denied the benefits associated with the previous overpayment for pension expense which they funded and that the pension asset should be eliminated from rate base. Staff Exhibit 14.0 at 23.

4. North Shore / Peoples Gas Response

The Utilities observe that GCI and Staff would have the Commission subtract the Utilities' OPEB liabilities from their rate bases, and further have it ignore Peoples Gas' pension asset and North Shore's pension liability and their pension contributions. The AG's Initial Brief (at 11-13), and the City-CUB Initial Brief (at 16-18), take that position without even mentioning the Utilities' pension asset/liability and pension plan contributions, much less providing any grounds for disregarding them while including the OPEB liabilities. GCI and Staff's proposed reductions of $55,563,000 and $7,094,000 from the rate bases of Peoples Gas and North Shore, respectively, are unfair and one-sided and should be rejected, the Utilities here argue.

The Utilities observe Staff to claim that subtracting the OPEB liabilities from rate base but ignoring the pension asset/liability is consistent with "ratemaking theory" because "the respective asset/liability was not created with funds provided by shareholders. Because these amounts were not provided by shareholders, shareholders do not need to earn a return on such amounts. (Staff Exhibit 14.0 at 22)."

Staff Init. Br. at 18. According to the Utilities, Staff's claim completely ignores the uncontested facts that Peoples Gas' net pension asset reflects that it contributed $15,278,614 to the pension plan during the test year, while North Shore's very small pension liability reflects that it contributed $1,862,257 to the pension plan during the test year. NS-PGL Ex. LMK-3.0 at 3. The Utilities maintain that ratepayers have benefited from those contributions. In calculating their proposed revenue requirements, the levels of pension expense in the test year were reduced by the Utilities' *pro forma* adjustments to reflect the lower levels of pension expense in fiscal year 2007, in the gross amounts of $1,277,000 as to Peoples Gas and $490,000 as to North Shore. PGL Ex. SF-1.0 at 27; PGL Ex. SF-1.1, Sched. C-1, column [D], Sched. C-2, at 1, line 15, and Sched. C-2.15, NS Ex. SF-1.0 at 25; NS Ex. SF-1.1, Sched. C-1, column [D], Sched. C-2, at 2, line 15, and Sched. C-2.15.

The Utilities note Staff to cite the 2004 and 1995 Nicor Gas rate cases where the Commission approved rate bases that reflected deductions for OPEB liabilities but did not incorporate pension assets. But, as the Utilities see Staff to acknowledge, in both of these cases the Commission found, as a matter of fact, that the pension assets were created by ratepayer-supplied funds. Staff Init. Br. at 18.

The Utilities observe that the Commission expressly noted, in the 2004 case, that Nicor Gas acknowledged making no pension plan contributions since the 1995 case. In re Northern Illinois Gas Co., ICC Docket No. 04-0779, Order at 2, Sept. 20, 2005 ("Nicor 2005"). Similarly, they note, the Order in the 1995 case indicates that the pension balance had gone from negative to positive since the utility's 1987 rate case without any pension plan contributions. In re Northern Illinois Gas Co., ICC Docket No. 95-0219, 1996 Ill. PUC Lexis 204, *20, Order, April 3, 1996 ("Nicor *1996*"). And, the Commission's order in Nicor 1996 distinguished the Commission's approval of inclusion of a pension asset in rate base In re Central Illinois Light Co., Docket No. 94-0040, Order, Dec. 12, 1994, on the grounds that the utility there, unlike Nicor Gas, had made pension plan contributions and the inclusion was not a contested issue. Nicor 1996 at *22. Thus, the Utilities assert, the Nicor 2005 and Nicor 1996 Orders do not support Staff's and GCI's proposed adjustments, because the relevant facts as relied upon by the Commission are not the same, and the more telling 1994 CILCO case supports inclusion.

According to the Utilities, Staff's witness also referenced the Commission's exclusion of a pension asset in In re Commonwealth Edison Co., ICC Docket No. 05-0597, Order at 38-40, July 26, 2006, ("ComEd 2006"). Staff Ex. 14.0 at 24. In ComEd 2006, the Utilities observe, the Order on Rehearing did not include the pension asset in rate base, but it allowed the utility to recover a rate of return (based on the cost of long-term debt) on a pension plan contribution that it made shortly after the test year, that was funded by an equity contribution from the utility's ultimate parent company, and that was a major factor in a *pro forma* adjustment to reflect a lower level of pension expense in the year after the test year. Order on Rehearing at 28-29, Docket 05-0597 (December 20, 2006).

As such, the Utilities assert that GCI's and Staff's position, i.e., that OPEB liabilities should be deducted when calculating the Utilities' rate bases, should be

rejected. The proposed reductions are incomplete and one-sided in that they exclude Peoples Gas' net pension asset of $110 million, to which Peoples Gas contributed over $15 million in the test year, along with North Shore's net pension liability of $24,000. In the alternative, if the OPEB liabilities are to be deducted, then Peoples Gas' net pension asset of $110,000,000 and North Shore's net pension liability of $24,000 also should be incorporated in the calculation of their rate bases. Further in the alternative, the Utilities maintain, if the OPEB liabilities are to be deducted, then at a minimum, Peoples Gas' contributions of $15,278,614 and North Shore's contributions of $1,862,247 to the pension plan also should be incorporated in the calculation of their rate bases.

5. Commission Analysis and Conclusion

The Commission agrees with the positions asserted by GCI and Staff. Their arguments are persuasive and fully supported by the evidence. Further, they have each established that the treatment we are being urged to assign to this item today, is the same the treatment that we adopted in a number of previous decisions. On all these grounds, the Commission accepts that a rate base deduction of $7,094,000 ($4,074,000 net of related deferred taxes) is required for the North Shore accrued OPEB liability and a rate base deduction of $55,653,000 ($31,570,000 net of related deferred taxes) is required for the Peoples Gas accrued OPEB liability in the determination of the Utilities' rate bases. *See* GCI Ex. 2.0 at 13.

Further, we note that the underlying rationale for these adjustments is that such funds are supplied by ratepayers and not by shareholders such that shareholders are not entitled to earn a return on these funds. Accordingly, the undisputed record showing that Peoples Gas and North Shore contributed $15,278,614 and $1,862,247, respectively, to the pension plans during the test year, does not change the treatment of the OPEB liability. Nor are we convinced that such contributions should impact shareholders, given that these funds were provided by ratepayers through the collection of utility revenues. We observe no discussion of or opposition to this particular recalculation that the Utilities propose on basis of their contribution, however, it appears to the Commission that recognizing these contributions is inconsistent with, the theoretical basis that we are applying here, i.e, these contributions are ratepayer-funded.

The Commission finds that the Utilities' OPEB liabilities will be deducted, and, for the reasons provided by Staff, Peoples Gas' contributions of $15,278,614 and North Shore's contributions of $1,862,247 to the pension plan should not be incorporated into the calculation of the rate bases.

H. ADIT (Derivative Adjustments from Uncontested and Contested Issues)

Other than GCI's two uncontested proposed adjustments discussed in Section II(B)(5) and (6) of this Order, Staff and Intervenors have not proposed any independent adjustments to ADIT as such. Accordingly, and as to ADIT, our Order need only make derivative calculations reflecting the approved adjustments that have derivative impacts on ADIT.

I. Overall Conclusion on Rate Bases

Based on the gas utility rate base as originally proposed by Peoples Gas along with the conclusions *supra*, the gas utility rate base for Peoples Gas approved for purposes of this proceeding is $1,212,203,000. The rate base may be summarized as follows:

Peoples Gas Rate Base (in thousands)

Description	Rate Base
	$
Gross Utility Plant	2,429,226
Accumulated Provision for Depreciation and Amortization	(934,152)
	$
Net Plant	1,495,074
Additions to Rate Base:	
Materials and Supplies	8,796
Cash Working Capital	25,514
Gas in Storage	46,390
Budget Plan Balances	14,080
Unamortized Rate Case Expense	-
Pension Contribution	-
Deductions From Rate Base:	
Accumulated Deferred Income Taxes	(284,954)
Pre-1971 Investment Tax Credits	(54)
Reserve for Injuries and Damages	(4,422)
Customer Advances for Construction	(392)
Customer Deposits	(32,176)
Accrued Postretirement Benefits Other than Pensions ("OPEB")	(55,653)
Rate Base	$

	1,212,203

Based on the gas utility rate base as originally proposed by North Shore along with the conclusions *supra*, the gas utility rate base for North Shore approved for purposes of this proceeding is $182,028,000. The rate base may be summarized as follows:

North Shore Rate Base (in thousands)

Description	Rate Base
	$
Gross Utility Plant	378,323
Accumulated Provision for Depreciation and Amortization	(148,561)
	-
	$
Net Plant	229,762
Additions to Rate Base:	
Materials and Supplies	1,539
Cash Working Capital	2,986
Gas in Storage	849
Budget Plan Balances	-
Unamortized Rate Case Expense	-
Pension Contribution	-
Deductions From Rate Base:	
Accumulated Deferred Income Taxes	(41,345)
Customer Advances for Construction	(748)
Cusomer Deposits	(2,860)
Cash Working Capital	(1,061)
Accrued Postretirement Benefits Other than Pensions ("OPEB")	(7,094)
	$
Rate Base	182,028

The development of the approved gas utility rate bases adopted for Peoples Gas and North Shore for purposes of this proceeding are shown in Appendices A and B, respectively, to this Order.

III. OPERATING EXPENSES

A. Overview

In the course of this proceeding, the Utilities have agreed to or accepted (for purposes of narrowing the issues) a total of 18 different adjustments to operating expenses proposed by Staff and the GCI. These uncontested issues are being considered in Section III(B) of this Order.

There are also five contested adjustments to operating expenses, based on Staff's proposed adjustments. Further, the GCI propose one contested adjustment to operating expenses that essentially is the same as one of Staff's proposals. All of the adjustments in dispute are being discussed in Section III(C) of this Order.

B. Uncontested Issues

1. Storage Expenses (Compressor Station Fuel Expenses) (PGL)

a) The Record

Peoples Gas witness Kallas accepted a GCI proposal to adjust Peoples Gas' expenses relating to compressor station operating fuel as long as it was recalculated based on updated fuel prices and fiscal year 2006 volumes, which resulted in a $953,000 adjustment (gross amount). PG-NGL Ex. LK-2.0, 14:294-309; PGL Ex. LK-2.3. GCI witness Effron agreed with that recalculated amount. GCI Ex. 5.0 at 12.

b) Commission Analysis and Conclusion.

The Commission finds that the proposed adjustment to Peoples Gas' expenses relating to compressor station operating fuel as revised, resulting in a $953,000 adjustment (gross amount) to Peoples Gas' operating expenses, is uncontested, reasonable and appropriate, and therefore approves it.

2. Distribution Expenses

a) Non-Payroll Expenses Inflation

(1) The Record

The Utilities proposed *pro forma* adjustments for expected 2007 inflation in non-payroll expenses of $3,084,000 as to Peoples Gas and $542,000 as to North Shore (gross amounts). PGL Ex. SF-2.0 at 27; NS Ex. SF-2.0 at 26. Staff witness Pearce proposed removing from each Company's operating expenses a pro forma adjustment to reflect 2007 inflation for non-payroll expenses. Ms. Pearce's recommendation was made for the reason that 83 Ill. Adm. Code 287.40 does not allow pro forma adjustments to the test year for the application of inflation factors in lieu of a particularized study of individual expense components and the Utilities' *pro forma* adjustment was not known and measurable. Staff Ex. 2.0 at 3-4. In order to narrow issues, the Utilities were willing to withdraw the proposed *pro forma* non-payroll expenses inflation adjustments given Staff and GCI contentions that their proposal was inconsistent with a rule provision regarding adjustments based on attrition and inflation factors and that the adjustments were insufficiently particularized to be known and

measurable. NS-PGL Ex. SF-2.0 at 4-5:103 and fn. 2, 12-13, NS-PGL Exs. SF-2.3P, 2.7P, and 2.8P.

(2) Commission Analysis and Conclusion

The Commission finds that the withdrawal of the Utilities' *pro forma* non-payroll expenses inflation adjustments to be uncontested. Therefore, we approve the withdrawal.

b) Customer Installation Expenses (North Shore)

(1) The Record

Staff witness Pearce proposed an adjustment for North Shore only to remove from North Shore's test year operating expenses an amount which corrected an error from 2005. As Ms. Pearce explained, the correction of the error in 2006 caused the balance of expense in account 879 to be overstated by $175,000. Without Staff's adjustment, the test year amount for the account would not be reflective of normal operations. Staff Ex. 2.0 at 20. In order to narrow the issues, North Shore does not contest the removal of $175,000 of customer installation expenses (gross amount) proposed by Staff witness Pearce. NS-PGL Ex. SF-2.0 at 4-5.

(2) Commission Analysis and Conclusion

The Commission finds that the removal of $175,000 of customer installation expenses (gross amount) from North Shore's operating expenses is uncontested and reasonable. Therefore, the adjustment is approved.

c) City of Chicago Resurfacing Expenses (PGL)

(1) The Record

Peoples Gas, in direct testimony, proposed the *pro forma* adjustment for City of Chicago resurfacing expenses (which has rate base and operating expenses components) in the gross amounts amount of $1,400,000 (rate base) and $2,100,000 (expense). PGL Ex. SF-1.0 at 19, 30; PGL Ex. SF-1.1, Scheds. B-2.2, C-2.28. In rebuttal testimony, Peoples Gas updated its *pro forma* adjustments for City of Chicago resurfacing expenses providing for additional gross amounts of $4,397,000 (rate base) and $6,596,000 (expense). NS-PGL Ex. SF-2.0 at 12-13; NS-PGL Exs. SF-2.3P and 2.7P. Peoples Gas did not contest any further the adjustments by GCI that reduce Peoples Gas' rebuttal testimony updated figures by the gross amounts as to rate base of $1,080,000 and as to operating expenses of $1,620,000. NS-PGL Ex. 4.0 at 6.

(2) Commission Analysis and Conclusion.

The Commission finds that the *pro forma* adjustments for City of Chicago resurfacing expenses as updated in Peoples Gas' rebuttal testimony, subject to the revisions proposed by GCI and accepted by Peoples Gas in surrebuttal testimony, which reduce rate base (gross plant) by the gross amounts of $1,080,000 and operating expenses by $1,620,000 from the updated levels in Peoples Gas' rebuttal testimony, are not contested, reasonable, and appropriate. Therefore, these are approved.

3. Customer Accounts Expenses (Uncollectible Accounts Expenses)

a) The Record

GCI witness Effron recalculated proposed adjustments to Peoples Gas' and North Shore's operating expenses relating to uncollectible accounts expenses and Staff withdrew its proposed adjustment. North Shore and Peoples Gas witness Kallas responded that the Utilities were willing to accept the GCI proposals, only if these were recalculated based on updated fuel prices and fiscal year 2006 volumes, which would result in adjustments of $3,283,000 as to Peoples Gas, and $103,000 as to North Shore (gross amounts). NS-PGL Ex. LK-2.0 REV at 14-15; NS-PGL Ex. LK-2.3. GCI witness Effron agreed with these recalculated amounts. GCI Ex. 5.0 at 9-10.

b) Commission Analysis and Conclusion

The Commission finds that adjustments to Peoples Gas' and North Shore's operating expenses that reduce uncollectible accounts expenses by $3,283,000 for Peoples Gas, and by $103,000 for North Shore (gross amounts), are uncontested and reasonable. Therefore, we approve these adjustments.

4. Customer Service and Information Expenses

a) "Advertising" Expenses

(1) The Record

In his direct testimony, Staff witness Kahle proposed adjustments to the Utilities' Advertising Expenses for expenses that are of a promotional, goodwill or institutional nature (Staff Ex. 3.0, Schedules 3.2 N and P) on grounds that Section 9-225 of the Act prohibits them from being considered for the purposes of rates. Staff Ex. 3.0 at 10-11. In their rebuttal testimony, and in order to narrow contested issues, the Utilities accepted Mr. Kahle's adjustments. North Shore/Peoples Gas Ex. SF-2.0 at 5. As such, North Shore and PGL do not contest Staff witness Kahle's proposed adjustments to remove what he contended were promotional, goodwill, or institutional advertising expenses from operating expenses in the gross amounts of $308,000 as to Peoples Gas and $43,000 as to North Sore. NS-PGL Ex. SF-2.0 at 4-5.

(2) Commission Analysis and Conclusion

The Commission finds that the adjustments to Peoples Gas' and North Shore's operating expenses to reduce "advertising" expenses by $308,000 for Peoples Gas and by $43,000 for North Shore (gross amounts), are uncontested. These are each reasonable and thus, we approve the adjustments.

b) Dues and Memberships Expenses (PGL)

(1) The Record

In his direct testimony, Staff witness Kahle proposed adjustments to the Utility's Dues and Membership Expenses for membership dues associated with such organizations as the Chicago Club, the Mid-America Club and University Club of Chicago on account that these membership dues represent promotional and goodwill

practices, Staff Ex. 15.0, Schedule 3.4 P, which Mr. Kahle considered to be unnecessary in providing utility service. In its rebuttal testimony, and in order to narrow contested issues, Peoples Gas accepted Mr. Kahle's adjustments. North Shore/Peoples Gas Ex. SF-2.0 at 5. As such, Peoples Gas does not contest Staff witness Kahle's proposed adjustment to remove certain membership dues in the gross amount of $14,000 from Peoples Gas' operating expenses. NS-PGL Ex. SF-2.0 at 4- 5.

(2) Commission Analysis and Conclusion

The Commission finds that the reduction in the gross amount of $14,000 in Peoples Gas' operating expenses, relating to certain membership dues is not contested and is reasonable. Therefore, we approve this reduction as stated.

5. Administrative & General Expenses

a) Civic, Political, and Related Activities Expenses

(1) The Record

In Schedules 1.9 P and N, Staff witness Hathhorn disallowed $80,000 and $11,000, respectively, in expenses allocated to the Utilities from Peoples Energy Corporation ("PEC") for civic, political and related activities on account that these expenses are ineligible for rate recovery according to Section 9-224 of the Act. The statute bars any expenses expended for political activity or lobbying from rates. Staff Ex. 1 at 12-13. North Shore and Peoples Gas do not contest Staff witness Hathhorn's proposal to adjust Peoples Gas' operating expense by $80,000 and North Shore's operating expense by $11,000 (gross amounts) due to the expenses being classified as civic, political and related activities. NS-PGL Ex. SF-2.0 at 4-5.

(2) Commission Analysis and Conclusion

The Commission finds that Staff's proposals to reduce Peoples Gas' operating expenses by $80,000 and North Shore's operating expenses by $11,000 (gross amounts) due to the expenses being classified as civic, political, and related activities are not contested and are reasonable. Therefore, these adjustments are approved.

b) Employee Recreation Expenses

(1) The Record

In Schedules 1.14 P and N, Staff witness Hathhorn disallowed $54,000 and $7,000 in payment of employee recreation expenses allocated to the Utilities from PEC for professional sporting event outings, picnics, and other social events not necessary to provide utility services. Staff Ex. 1 at 18. The Utilities do not contest Staff witness Hathhorn's proposed adjustments to remove expenses for employee recreation in the gross amounts of $54,000 as to PGL and $7,000 as to North Shore from operating expenses. NS-PGL Ex. SF-2.0 at 4-5.

(2) Commission Analysis and Conclusion

The Commission finds that Staff's proposals to reduce Peoples Gas' operating expenses by $54,000 and North Shore's operating expenses by $7,000 (gross

amounts) for activities relating to employee recreation are uncontested and reasonable. For these reasons, we approve the disallowances in these amounts.

c) Corporate Rebill of Income Tax Penalties

(1) The Record

In Schedules 1.13 P and N, Staff witness Hathhorn disallowed $35,000 and $5,000, respectively, in payments of a federal income tax penalty allocated to the Utilities from PEC, on account that, generally, these types of penalties are not eligible for rate recovery as the charges were incurred for violation of a regulatory statute. Staff Ex. 1, at 17-18. The Utilities do not contest Staff witness Hathhorn's proposed adjustments to remove the rebilling of income tax penalties from Peoples Energy Corporation to the Utilities in the gross amounts of $35,000 as to Peoples Gas and $5,000 as to North Shore. NS-PGL Ex. SF-2.0 at 4-5.

(2) Commission Analysis and Conclusion

The Commission finds that Staff witness Hathhorn's proposed adjustments to remove the rebilling of income tax penalties from Peoples Energy Corporation to the Utilities in the gross amounts of $35,000 as to Peoples Gas and $5,000 as to North Shore are uncontested and reasonable. As such, these adjustments are approved.

d) Lobbying Expenses

(1) The Record

In his direct testimony, Staff witness Kahle proposed adjustments to the Utilities' Operating Expenses payroll associated with lobbying activities, Staff Ex. 3.0, Schedules 3.3 N and P, for reasons that such expenses are prohibited from rate recovery under Section 9-224 of the Act. In rebuttal testimony, and in order to narrow contested issues the Utilities accepted Mr. Kahle's proposed adjustments that would disallow lobbying expenses from rate base and operating expenses in the gross amounts of $12,000 (capitalized) and $67,000 (operating expenses) as to Peoples Gas; and $3,000 (capitalized) and $13,000 (operating expenses) as to North Shore. NS-PGL Ex. SF-2.0 at 4-5.

(2) Commission Analysis and Conclusion

The Commission finds that the proposed adjustments to remove lobbying expenses from rate base and operating expenses in the gross amounts of $12,000 (capitalized) and $67,000 (operating expenses) as to Peoples Gas and $3,000 (capitalized) and $13,000 (operating expenses) as to North Shore are not contested and are reasonable. Therefore, we accept and approve these adjustments.

e) Executive Perquisites Expenses

(1) The Record

Staff witness Pearce proposed an adjustment to remove from the test year executive perquisites for the Utilities. Based upon the Utilities' response to a data request, the executive perquisites included reimbursements to officers and high level executives for: auto allowances, supplemental life insurance, executive physicals, and

flexible perquisite allowances to cover excess liability insurance, financial counseling and home office equipment. Ms. Pearce found these expenses to be discretionary and unnecessary for the provision of utility service. She further noted that the perquisites are awarded to a few top executives in addition to salaries and other benefits. Staff Ex. 2.0 at 19. The Utilities do not contest Staff witness Pearce's proposed adjustments to remove executive perquisites in the gross amounts of $170,000 as to Peoples Gas and $15,000 as to North Shore from operating expenses. NS-PGL Ex. SF-2.0 at 4-5.

(2) Commission Analysis and Conclusion

The Commission finds that Staff's proposed adjustments to remove executive perquisites from operating expenses in the gross amounts of $170,000 as to Peoples Gas and $15,000 as to North Shore are uncontested and reasonable. Therefore, we approve these adjustments.

f) Termination Costs (PGL)

(1) The Record.

Staff witness Pearce proposed an adjustment for Peoples Gas to remove termination allowances. Ms. Pearce explained that her adjustment removes from the test year expense which is not reflective of normal utility operations. Staff Ex. 2.0 at 20-21. The record shows that Peoples Gas does not contest Staff witness Pearce's proposed adjustment to remove a gross amount of $259,000 in termination costs from Peoples Gas' operating expenses. NS-PGL Ex. SF-2.0 at 4-5.

(2) Commission Analysis and Conclusion

The Commission finds that the proposed adjustment to remove a gross amount of $259,000 in termination costs from Peoples Gas' operating expenses is not contested and is reasonable in these premises. Therefore, the adjustment is approved.

g) Salaries and Wages Expenses

(1) The Record

North Shore and Peoples Gas proposed *pro forma* adjustments for salary and wage increases in the gross amounts of $3,576,000 for Peoples Gas and $431,000 for North Shore. PGL Ex. SF-1.0 at 26; PGL Ex. SF-1.1, Scheds. C-2.13, C-2.14; NS-Ex. SF-1.0 at 25; NS Ex. SF-1.1, Scheds. C-2.13, C-2.14. Staff witness Pearce proposed an adjustment for the Utilities for salaries and wages expenses to take into account a correction which the Utilities made to the underlying calculation for O & M union wage and nonunion merit increases for 2006 and O & M union wage and nonunion merit increases for 2007. Staff Ex. 2.0 at 21-22. The Utilities do not contest Staff witness Pearce's proposed adjustments, reflecting the Utilities' corrections to errors in their underlying calculations supporting their *pro forma* adjustments for salaries and wage increases, increasing operating expenses by the gross amounts of $124,000 as to Peoples Gas and $25,000 as to North Shore. NS-PGL Ex. SF-2.0 at 4-5.

(2) Commission Analysis and Conclusion

The Commission finds that Staff's proposed adjustments to the Utilities' salaries and wage increases, which increases *pro forma* operating expenses by the gross

amounts of $124,000 as to Peoples Gas and $25,000 as to North Shore, are uncontested and reasonable. Therefore, we approve these adjustments.

h) Medical and Insurance Expenses

(1) The Record

GCI witness Effron proposed adjustments to operating expenses, that would reduce Peoples Gas' medical and insurance expenses by the gross amount of $866,000, and also would reduce North Shore's medical and insurance expenses in the gross amount of $83,000. The record shows that the Utilities do not contest these adjustments. NS-PGL Ex. SF-2.0 at 4-5.

(2) Commission Analysis and Conclusion

The Commission finds that the proposed adjustments to operating expenses, reducing Peoples Gas' medical and insurance expenses by the gross amount of $866,000, and reducing North Shore's medical and insurance expenses by the gross amount of $83,000, to be uncontested and also reasonable. Therefore, we approve these adjustments.

i) Rate Case Expenses

(1) The Record

Initially, the Utilities proposed rate case expenses to be included in operating expenses, with the rate case expenses to be amortized over three years and with no adjustment to be made for carrying charge expenses. PGL Ex. 1.0 at 23; NS Ex. 1.0 at 22. And, in response to Staff and GCI's proposal that all rate case expenses be amortized over five years, Peoples Gas and North Shore stated that, if the five-year amortization period were to remain intact, they should be able to include the amortized amount in rate base. NS-PGL SF-2.0 at 6. In his direct testimony, Staff witness Griffin recommended a five year amortization period for rate case expenses instead of the three year period proposed by the Utilities. Staff Ex. 4.0 at 6-7. His five-year amortization period was based upon the average number of years between the most recent five rate cases while the Utilities' proposed three-year amortization period was based upon the average number of years between the most recent ten rate cases. Id. at 6. In order to narrow the issues, Utilities' witness Fiorella indicated that the Utilities would no longer contest the five-year amortization period. North Shore/Peoples Gas Ex. SF-4.0 at 5.

On the substantive matter, Peoples Gas and North Shore provided updated data on rate expense (actual amounts incurred and updated estimates for the remaining amounts) in their rebuttal testimony. NS-PGL SF-2.0 at 6-8; NS-PGL Exs. SF-2.9P and SF-2.9N. Based on his review, witness Griffin testified that Peoples Gas had supported $2,956,220 in total rate case expense and North Shore had supported $2,169,800 in total rate case expense. Staff Ex. 16.0 at 6.

Using a five-year amortization period for the supported showing of $2,956,220 in total rate case expense for Peoples Gas, and $2,169,800 in total rate case expense for North Shore, Mr. Griffin recommended a rate case expense for Peoples Gas equal to

$591,244 (Id. Schedule 16.1P, page 2 of 2) and recommended a rate case expense for North Shore equal to $433,960 (Id. Schedule 16.1N, page 2 of 2). To narrow the issues further, the Utilities did not contest Mr. Griffin's rate case expense for either Utility, North Shore/Peoples Gas Ex. SF-4.0 at 5, and further withdrew their proposal to include the unamortized portion in rate base (that Staff had opposed). Id. (Staff Ex. 16.0 at 2).

The Utilities do not contest the final revised proposed adjustments of Staff to operating expenses that reduce Peoples Gas' and North Shore's rate case expenses, as updated in rebuttal testimony, by the gross amounts of $680,000 and $690,000, respectively, with all rate case expenses to be amortized over five years, and excluding the amortized amount from rate base. The Utilities and Staff agree that the annual amortization for rate case expense for North Shore and Peoples Gas should be $433,960 and $591,244, respectively, based upon a five year amortization period with no unamortized balance in rate base.

(2) Commission Analysis and Conclusion

The Commission finds that the proposed adjustments in Staff's rebuttal testimony to the amounts of the updated rate case expenses of the Utilities are reasonable and uncontested. Further, we find that Staff's and GCI's proposals to amortize rate case expenses over a five-year period without carrying charges, are uncontested and reasonable. For all these reasons, each of the adjustments reflected above are here approved.

j) Franchise Requirements Expenses (North Shore)

(1) The Record

In response to GCI witness Effron's direct testimony wherein he recalculated the proposed adjustment to North Shore's operating expenses relating to franchise requirements expenses, North Shore and Peoples Gas witness Kallas stated that North Shore was willing to accept the proposal, if it were recalculated based on updated fuel prices and fiscal year 2006 volumes, which results in a $584,000 adjustment (gross amount). NS-PGL Ex. LK-2.0 REV at 14; NS-PGL Ex. LK-2.3. Mr. Effron agreed with that recalculated amount. Effron Reb., GCI Ex. 5.0 at 11. No other witness disagreed.

(2) Commission Analysis and Conclusion

The Commission finds that the proposed reduction in North Shore's operating expenses in the amount of $584,000 (gross amount) is uncontested and it is reasonable. Therefore, we approve the reduction in just this amount.

k) PEC Officer Costs and Directors Fees

(1) The Record

In Schedules 1.12 P and N, Staff disallowed $702,000 and $100,000, respectively, to reallocate a reasonable portion of Peoples Energy Corporation ("PEC") officer costs and director fees to PEC, the Utilities' parent company at the time, rather than the Utilities. Staff Ex. 1 at 15-17. The Utilities accepted the adjustments in surrebuttal testimony in order to narrow the contested issues. NS-PGL Ex. SF-4.0 at 3. The Utilities do not contest Staff witness Hathhorn's revised proposed adjustments to

operating expenses that removes Peoples Energy Corporation officer costs and directors' fees that were allocated to Peoples Gas in the gross amount of $702,000 and to North Shore in the amount of $100,000. NS-PGL Ex. SF-4.0 at 6.

(2) Commission Analysis and Conclusion

The Commission finds that Staff's revised proposed adjustments to remove officer costs and directors' fees that were allocated to Peoples Gas in the gross amount of $702,000, and to North Shore in the gross amount of $100,000, are uncontested and reasonable in these premises. Therefore, these adjustments are approved.

6. Taxes Other Than Income Taxes (Personal Property Taxes).

a) The Record

In rebuttal testimony, Peoples Gas revised its Taxes Other Than Income Taxes to include a proposed personal property taxes gross amount increase of $1,181,000, reflecting a court decision. NS-PGL Ex. 2.0 at 13; NS-PGL Ex. SF-2.8 P. No party contested this adjustment.

b) Commission Analysis and Conclusion

The Commission finds that the inclusion for Peoples Gas of an additional gross amount of $1,181,000 in personal property taxes in Taxes Other Than Income Taxes pursuant to a recent court decision is not challenged by any party and it is reasonable and appropriate under the circumstances. Therefore, this revision is approved.

7. Income Taxes (Interest Synchronization).

a) The Record

Initially, Peoples Gas proposed that its Interest Synchronization component of income taxes be calculated as $1,894,000, thus reducing income taxes by that amount. PGL Ex. SF-1.0 at 25; PGL SF-Ex. 1.1, Sched. C-2.8. North Shore proposed that its Interest Synchronization component of income taxes be calculated as $451,000, thus reducing income taxes by that amount. NS Ex. SF-1.0 at 24; NS Ex. SF-1.1, Sched. C-2.8. The rebuttal testimony of Utilities witness Fiorella, however, shows that the Utilities do not contest Staff's proposal that the Interest Synchronization component of income taxes should be recalculated, for purposes of final approved revenue requirement calculations, based on the final approved rate base times the weighted cost of debt. NS-PGL Ex. SF-2.0 at 4-5. Thus, all parties are in agreement on the matter. Staff Ex. 1.0 at 7 and Scheds. 1.5 P and 1.5 N; GCI Ex. 2.0, Sched. C-4.

b) Commission Analysis and Conclusion.

The Commission finds that Staff's proposal that, for purposes of final approved revenue requirement calculations, the Interest Synchronization component of income taxes should be recalculated based on the final approved rate base times the weighted cost of debt, is uncontested and is reasonable. Therefore, it is approved.

8. Meter Reading

a) The Record.

Staff initially raised a concern with the number of consecutively unread meters. In rebuttal testimony, however, Staff expressed general satisfaction with Peoples Gas' responses and suggested that Peoples Gas should provide quarterly updates (within 30 days after the end of each quarter) to the Director of the Energy Division and the Director of the Consumer Services Division of Staff, summarizing the number of consecutively unread meters without a reading for more than six months, or three months in the case of ERTed meters. Staff Ex. 23.0 at 20-23 & 25-26. Peoples Gas agreed to provide these reports. PGL-NS Ex. ED-3.0 at 3-4.

b) Commission Analysis and Conclusion.

No party opposes the agreement to provide the reports. As such, the proposal is adopted by the Commission.

C. Contested Issues

1. Storage Expenses.

a) Crankshaft Repair Expenses (PGL).

(1) Peoples Gas

Peoples Gas' test year operating expenses, as originally proposed, include $546,000 of repair expenses related to a failed crankshaft on the Manlove Field compressor. PGL Ex. LK-1.0 at 13. Given the unusual nature of this failed equipment, GCI witness Effron proposed that Peoples Gas be allowed to recover these expenses, but only on an amortized basis over a four year period. This means that the test year amount of $546,000 would be reduced by $410,000, i.e., to $136,000, in calculating the revenue requirement. GCI Ex. 2.0 at 32-33 and Sched. C-2 (Peoples Gas). In its responsive testimony, Peoples Gas accepted GCI's proposed adjustment. NS-PGL Ex. 2.0 at 4-5, & 12. This proposal, the Utility asserts, takes a reasonable and balanced view. It recognizes that Peoples Gas actually incurred these expenses in the test year and it further considers the unusual nature of the expense.

(2) Staff

Staff recommends a reduction to Peoples Gas' operating and maintenance expense ("O&M") in the amount of $136,000 to account for the non-recurring experience of the gas compressor repair, Staff Ex. 23.0 at 20, Staff's review of the circumstances demonstrate that the expense associated with compressor repair was a non-recurring expense, and all of the cost associated with that repair should be disallowed.

Staff's conclusion stems from the response to a data request which indicated that the expected life of the gas compressor was virtually indefinite and limited only by the ability to obtain replacement parts. Peoples Gas also indicated that over the past 20 years, it had never experienced a major repair of this magnitude. Id. at 32-33. And, Staff notes, Peoples Gas did not expect to incur major repairs with its large gas compressors in the foreseeable future. Id. at 33. Based on this information, Staff determined that the

expense associated with the gas compressor repair was a non-recurring expense and that the expense should be disallowed. Id. at 34.

Staff notes Mr. Effron to agree that the compressor repair was a non-recurring item. Staff Ex. 23.0 at 19-20. And, he further indicated that a utility's actual expenses in a test year should be adjusted to reflect, among other things, the elimination of any abnormal or non-recurring items in order to reflect normal operations in the determination of revenue requirements. GCI Ex. 2.0 at 21. It is on these matters that Staff continues to recommend the removal of all of the O&M expense associated with the gas compressor repair. The valuation of that adjustment is the difference between Staff's recommendation of $546,000 and the $410,000 amount that Peoples Gas agreed upon with GCI, or $136,000. Staff Ex. 23.0 at 20.

Peoples Gas' main reason for disagreeing with Staff's proposal to disallow the compressor repair cost is the possibility that other non-recurring expenses will occur each year. According to Staff, however, it provided no support for this statement or any examples that Peoples Gas historic non-recurring expenses are in any fashion equivalent in magnitude to the costs associated with repairing the gas compressor. Therefore, Staff argues, its recommendation to disallow all of the expenses associated with the compressor repair on the basis of its non-recurring nature, should be accepted.

(3) Peoples Gas Response

Peoples Gas urges the Commission to allow recovery of these expenses, but only on an amortized basis over a four year period as proposed by GCI witness Effron. This means that the test year amount of $546,000 would be reduced by $410,000, i.e., to $136,000, in calculating the revenue requirement. GCI Ex. 2.0 at 32-33 and Sched. C-2 (Peoples Gas). Peoples Gas accepted GCI's proposed adjustment, and reflected that adjustment in its rebuttal and final revenue requirement calculations. NS-PGL Ex. SF-2.0 at 4, 5 & 12; NS-PGL Ex. SF-2.5P, column [D]; NS-PGL Ex. SF-2.6P, p. 3, column [E]; NS-PGL Ex. SF-4.3P, column [C]. According to Peoples Gas, the GCI's adjustment is reasonable.

In contrast, Peoples Gas observes Staff to propose a complete denial of recovery of the $546,000 and, as such, it would eliminate $136,000 in the revenue requirement calculation. Staff Ex. 11.0 at 32-34; Staff Ex. 23.0 at 19-20.

Peoples Gas maintains that Staff's proposal is far less reasonable in the situation, because it makes no attempt at balancing all of the factors. Staff simply denies all cost recovery of an expense that actually incurred. Moreover, Peoples Gas notes that Staff's proposal at this juncture is theoretically inconsistent with the position it takes regarding the matter of collection agency fees (where Staff contends that a level of that expense in the test year that is much lower than the level in prior years should be used in calculating the revenue requirement). Peoples Gas asks that the GCI's proposal, which it supports, be adopted. While Peoples Gas agrees that the repair of the gas compressor might be a single "non-recurring" event, it directs attention to the scope of Peoples Gas' distribution operations. Given the span of its operations, Peoples Gas argues, it is likely to experience different types of non-recurring events each year. North Shore/Peoples Gas Ex. SF-2.0 at 12.

Peoples Gas notes that there is no evidence to deny that the expenses were prudent, reasonable, and needed. Staff merely makes the point that the crankshaft failure was an unusual event, but that does not support denying recovery of these necessary expenses. Given the broad scope of Peoples Gas' operations, Peoples Gas argues, it is likely to experience different non-recurring events each year. NS-PGL Ex. SF-4.0 at 10.

(4) Commission Analysis and Conclusion

No party denies that the expenses were prudent, reasonable, and necessary. No party disputes that the repair expense occurred in the test year. Likewise, no party disputes that Peoples Gas' repair of the gas compressor was a non-recurring event. Taking these points together, the only question is whether the expense associated with this non-recurring event should be amortized or disallowed.

The Commission accepts GCI's proposal as fair and reasonable and finds that the Utilities should be allowed to recover $136,000 as the amortization amount for crankshaft repair expenses. This acknowledges that the expense did occur in the test year but is not expected to be a recurring event. It also recognizes that, given the vast scope of its operations, the Utility will, more likely than not, incur another kind of unusual expense. Taking these factors as a whole, the GCI's proposal is fair and appropriate.

Staff makes the point that the crankshaft failure was a very unusual event, but that is only one factor to be considered. Standing alone, it does not support denying all recovery of a prudent, reasonable, and necessary expense.

The amortized amount of $136,000 is fair and reasonable. It is recommended by GCI's witness and supported by Peoples Gas. GCI Ex. 2.0 at 32-33 and Sched. C-2 (Peoples Gas); NS-PGL Ex. SF-2.0 at 4, 5 & 12; NS-PGL Ex. SF-2.5P, column [D]; NS-PGL Ex. SF-2.6P, p. 3, column [E]; NS-PGL Ex. SF-4.3P, column [C]. Peoples Gas should be allowed to recover this amount.

b) Hub Services (PGL) (Addressed in Section V, below)

2. Customer Accounts Expenses (Collection Agency Fees)

a) North Shore/Peoples Gas

In calculating their revenue requirements, the Utilities substituted three year averages of the collection agency fees incurred in fiscal years 2003 through 2005 for the level in the test year. The fiscal year 2006 expense, they assert, was abnormally low due to the 2006 Gas Charge settlement. PGL Ex. SF-1.0 at 28; PGL Ex. SF-1.1, Sched. C-2.19; NS Ex. SF-1.0 at 26; NS Ex. SF-1.1, Sched. C-2.19. The effect of the settlement on the test year level of the fees was illustrated in the charts found on page 43 of the Utilities' Initial Brief.

b) Staff

In its Schedules 13.8 P and N, Staff disallows $1,770,000 and $76,000, respectively, and explains that these amounts represent each Company's proposed increase to normalize test year collection agency fees. According to Staff, the evidence

reflects that the unadjusted test year expense is more likely to recur in the future than each Company's calculated increase. Staff Ex. 13 at 6.

Staff notes the Utilities to contend that actual 2006 collection expenses were lower than normal due to the gas charge settlement, and propose a normalization adjustment to account for the alleged impact of the Settlement Agreement on collection costs. PGL Ex. SF-1.0 at 28; NS Ex. SF-1.0 at 26. As indicated in the Order entered by the Commission on March 28, 2006, in Docket 01-0707, the Utilities entered into a Settlement Agreement with certain parties to resolve certain gas charge reconciliation proceedings. As part of the Amendment and Addendum to the Settlement Agreement, Staff notes that the Utilities agreed to forgive certain outstanding debt and not pursue collection of those amounts. In Staff's view, however, the Utilities' historical expense experiences and the current trend of post test year collection agency fees do not support their contention. Staff Ex. 1 at 8-9.

Staff observes the Utilities to state that not only are 2006 fees understated due to the Settlement Agreement, but the 2007 fees as well. PGL-NS Ex. LK-2.0 at 5. In Staff's view, however, the evidence shows that not only are the 2006 expense levels lower than the Utilities' request, the trend of lower collection agency fees than in prior years continues presently in 2007.On this point, Staff notes the Utilities to also explain that it is not uncommon for collections to take place several years after the bill is turned over to a collection agency.

Staff acknowledges that the Utilities may be correct in that at some unknown point in time in the future, its collection agency fees may eventually rise back to the pre-settlement level. Due to the lag in collections, and resulting fees incurred, Staff maintains that the 2006 and 2007 expenses are far below the 2004 and previous years' amounts. For the period of time the rates from the instant proceeding will be in effect, Staff contends that the Utilities' proposed average based on the 2003 through 2005 experience is inappropriate and overstates the expected collection agency fees going forward. Staff Ex. 13 at 10.

According to Staff, the Utilities disagree that their adjustment represents an attempt to collect costs incurred from the Settlement Agreement. North Shore/Peoples Gas Ex. LK-2.0 at 6. The Utilities' opinion, Staff notes, appears to be derived from its understanding of the agreement as evidenced by the claim that: "[T]his adjustment follows the intent of the agreement to eliminate all effects of the settlement….This is no different than any other adjustment to historical costs that are impacted by unusual activity." Id.

Staff notes that the Utilities' adjustments are not "any adjustment for unusual activity" as they were borne out of the Utilities' conduct and settlement of the issues in Docket 01-0707. The settlement represents, at least in part, the return to ratepayers of costs that the Utilities should not have recovered as prudently incurred costs. Thus, Staff argues, the Utilities' adjustment to "eliminate all effects of the settlement" with respect to uncollectibles has the effect, contrary to the intent of the settlement, to treat all costs as prudently incurred costs. Staff Ex. 13 at 10-11.

c) North Shore/Peoples Gas Response

Staff proposes that the Utilities be required to use the test year level in calculating their revenue requirements, resulting in proposed disallowances in the gross amounts of $1,770,000 and $76,000 as to Peoples Gas and North Shore, respectively. Staff Ex. 1.0 at 8-12, Sched. 1.8P, p. 1, Sched. 1.8N, p. 1. Peoples Gas takes issue with Staff's proposal as being unsound.

Staff claims that the test year levels are more likely to recur in the period in which the rates set in this case will be in effect than the three-year average used by the Utilities. Staff Init. Br. at 29. The facts do not support, and instead are contrary to, that claim.

The Utilities note Staff to rely on the test year level and the partial data available for 2007. Staff Init. Br. at 30. They point out, however, that the rates to be set in this proceeding will go into effect in 2008. Moreover, they observe that Staff is not being consistent in arguing that the rates to be set in this case will only be in effect for a short period. In this respect, Utilities observe that Staff took the position that rate case expenses should be amortized over a five-year period, on the grounds that that was a more likely interval until the Utilities' next rate case (and, in order to narrow the issues, the Utilities accepted that proposal). Id. at 24.

The evidence, the Utilities assert, strongly shows that the three-year average of fiscal years 2003 through 2005 is more likely to recur in the years in which the rates being set will be in effect. North Shore and Peoples Gas refer the Commission to the testimony of their witness Kallas, who stated that:

> Collection agencies are used to collect on older bad debt accounts. Therefore, fiscal years 2006 and 2007 amounts are artificially low due to the Utilities' agreement to not attempt to collect accounts that had been written-off and remained uncollected as of September 30, 2005. Accounts written off subsequent to September 30, 2005, however are not forgiven and have been and will be assigned to collection agencies for collection. This will result in collection agency fees being substantially more than experienced in the test year. A good estimate of the expected level of collection agency fees for the first year that the rates set in this proceeding will be in effect is the fiscal year 2003 through 2005 average used in Mr. Fiorella's proposed adjustment. In other words, the averaging of actual experience not affected by the agreement (i.e., fiscal years 2003 through 2005) is much more indicative of normal activity and cost for this account.

NS-PGL Ex. LK-2.0 REV at 5.

Staff's position here, the Utilities contend, which calls for using an abnormally low test year value here, is inconsistent with what Staff is recommending for normalizing the level of injuries and damages expenses, as will be discussed in Section III(C)(3)(a) of this Order, *infra*.

Further, the Utilities dispute Staff claims that the their position somehow is in conflict with the "intent" of the provision of the Gas Charge settlement under which they

agreed to forgive certain debt owed in 2005 and not pursue collection of those amounts Staff Init. Br. at 30, 31. Nothing, they assert, could be more wrong. The uncontradicted evidence, the Utilities maintain, shows that the Utilities are not seeking to collect even one penny of the forgiven amounts, directly or indirectly. They are simply trying to include a normal level of collection agency fees in their revenue requirements used to set rates that will go into effect in 2008, and those fees do not in any way involve the forgiven amounts. NS-PGL Ex. LK-2.0 2REV at 6; NS-PGL Ex. LMK-3.0 at 3-4. For all these reasons, the Utilities argue, Staff's proposed adjustments are unwarranted and should be rejected.

d) Commission Analysis and Conclusion

On the basis of the evidence and arguments, the Commission approves the Utilities' adjusted collection agency fees levels and rejects Staff's proposed disallowances of $1,770,000 for Peoples Gas and $76,000 for North Shore. We are convinced that the Utilities' adjustments are appropriate in light of the abnormally low test year levels. We accept too, that the methodology they employ yields figures more likely to be representative of the expenses in the years in which the rates established in these proceedings will be in effect.

The Commission understands that there are purely tangential effects to the Settlement that have nothing to do with compliance of its terms. As such, the Utilities' 2006 and 2007 collection agency fees were (and likely should have been), vastly understated due to the Gas Charge settlement agreement. This is the only, albeit substantial, significance to be given to the Settlement in this instance and there is nothing improper in so doing. In other words, and contrary to what Staff would imply, the Utilities' proposal in this proceeding is in no way inconsistent with the terms of the Gas Charge settlement.

3. Administrative & General Expenses

a) Injuries and Damages Expenses

(1) North Shore / Peoples Gas

The Utilities incorporated their respective and appropriate levels of injuries and damages expenses in calculating their revenue requirements. Peoples Gas appropriately used the test year level, adjusted for a highly unusual credit recorded in fiscal year 2006 relating to a major claim that occurred in fiscal year 2002. PGL Ex. SF-1.0 at 19-21, 23 & 31; PGL Ex. SF-1.1, Sched. C-1, lines 13-14, Sched. C-2, line 30, and Sched. C-2.30. For its part, North Shore appropriately used its unadjusted test year level. NS Ex. SF-1.0 at 18-20; NS Ex. SF-1.1, Sched. C-1, lines 13-14; Sched. C-2.

(2) Staff

Staff witness Griffin proposes an adjustment to normalize injuries and damages expense. He observes Peoples Gas to have proposed an accrual of $6,192,000 (Staff Ex. 4.0, Schedule 4.4P, page 1 of 2) while North Shore proposed an accrual of $477,000. Id. Schedule 4.4N, page 1 of 2. Mr. Griffin explained that the Utilities' proposed accruals represented estimated amounts set aside for future claim payments. Id. at 8. Since the annual accruals can vary greatly from one year to the next, he

considers it is more appropriate to normalize the expense for ratemaking purposes. Id. At the outset, Mr. Griffin calculated his normalized expense by examining the five year period from 2002 to 2006 and computing an average percentage of claims paid against the annual accrual. He then took that percentage and applied it against the accrual for 2006 Injuries and Damages.

In rebuttal testimony, Mr. Griffin revised his adjustment to account for an inadvertent error and, to include payments made in 2002 through 2006 for amounts under $100,000. Staff Ex. 16.0 at 6-7. His rebuttal position incorporated a corrected normalized adjustment presented in the testimony of the Utilities' witness Kallas in schedules 16.2P and 16.2N.

Staff notes Mr. Griffin to have explained that the difference between the Utilities' proposal and his proposal is significant, i.e., the difference between normalized and actual injuries and damages expense is 14% for Peoples Gas and 22% for North Shore. Staff Ex. 16.0 at 7.

Responding to the argument that Mr. Griffin gave no reason for choosing a five year period, i.e. 2002 through 2006, Staff would point out that the Commission used a five year period when examining injuries and damages expenses in the Ameren Illinois Utilities' recent rate cases. AmerenCILCO, AmerenCIPS, and AmerenIP electric rate cases, Docket Nos. 06-0070/06-0071/06-0072 (consol.) Order (November 21, 2006) ("Ameren Order"). In using a five year period for his analysis, Staff argues, Mr. Griffin was guided by the Ameren Order.

Staff notes the Utilities to assert that the year 2002 should be excluded from the analysis. According to Staff, however, the Ameren Order clearly establishes that the Commission will reject attempts by parties to exclude years which are not true outliers. While Utilities' witness Kallas that four years should be used rather than the five years Mr. Griffin uses, North Shore/Peoples Gas Ex. LMK-3.0 at 5, Staff maintains that there is no showing on the Utilities' part that year 2002 is "so out of the norm as to be considered [an]'outlier." Id. at 48-49.

For all these reasons, Staff argues, the Commission should adopt Staff's position that North Shore and Peoples Gas' Injuries and Damages expense should be $373,000 and $5,442,000 respectively.

(3) North Shore / Peoples Gas Response

Utilities maintain that Staff's proposed adjustments to injuries and damages expenses are unwarranted and arbitrary. Given the "relative closeness" of the expense, Utilities assert, there is no good reason to have normalized Injuries and Damages expense. North Shore/Peoples Gas Ex. LMK-3.0, p. 5. Nor did Mr. Griffin ever explain why he chose to use a five- year period to normalize the expense. Id. Further, they take issue with the methodology being applied for the normalization, to wit:

(1) calculate the five year average of the accruals for these expenses over the period of fiscal years 2002 through 2006,

(2) calculate the five year average of actual payouts over that period,

(3) divide the latter by the former to develop a percentage, and

(4) multiply that percentage times the fiscal year 2006 accrual to obtain the allowed level to be included in the revenue requirement. *See* Staff Ex. 16.0, Scheds. 16.2 P and 16.2 N.

Staff's witness, in his direct testimony, contended that the levels of injuries and damages expenses fluctuate and therefore should be normalized; proposed the above methodology to set the levels; and cited in the Ameren Order. Staff Ex. 4.0 at 8-9. He offered no reason for selecting a five year normalization methodology, as opposed to some other period, apart from that citation.

In the course of the proceeding, the Utilities' witness noted data errors made by Staff's witness, and pointed out that normalization was not warranted in this instance. NS-PGL Ex. LK-2.0 REV, at 9-11. While Staff's witness corrected his data errors, the only view that that he expressed was that the differences between his corrected averages and the Utilities' proposed levels, 14% as to Peoples Gas and 22% as to North Shore, were significant to have adjustments should be made. Staff Ex. 16.0 at 7. And, the Utilities note, he still did not provide any specific support for his choice of the five year period that yielded those percentages.

In surrebuttal, Ms. Kallas continues to disagree with any need for normalization, and again points out that Staff's witness still has not provided any specific support for his choice of a five year period. Further, she sets out that using either a four or three year periods would not support Staff's proposed adjustments, and that, in fact, a four year average would increase the levels of injuries and damages expenses included in the revenue requirements of both of the Utilities. Specifically, Ms. Kallas' testimony states that:

> Considering the relative closeness of this expense in the test year to the five year period chosen by Mr. Griffin, there is no good reason this expense should be normalized. Moreover, Mr. Griffin does not explain why he chose to use five years. If four years were used for Peoples Gas (fiscal years 2003 through 2006), it would indicate a higher "normalized" expense than actual fiscal year 2006. If a three year period is chosen for Peoples Gas, the "normalized" expense would almost equal the fiscal year 2006 accrual. The results are even more significant for North Shore where excluding fiscal 2002 in the calculation results in cash payments much higher than accruals. NS-PGL Ex. LMK-3.0 at 5.

In the Ameren Order, the Utilities observe, Staff looked at five years of data, but then discarded, in each instance, data from the one year that was considered unrepresentative, which then resulted in Staff's use of a four-year average. Here, Utilities point out, the fiscal year 2002 data that Staff uses is far different from the data for the other four years, Staff Ex. 16.0, Scheds. 16.2 P and 16.2 N, and, as Ms. Kallas shows in her testimony, excluding that one year would result in increases, not decreases, in the levels of injuries and damages expenses included in the revenue requirements of both Utilities. In short, the Utilities argue, the Commission should reject Staff's proposed adjustments because: (1) there is no significant reason to normalize

these expenses; and (2) it is evident that Staff's choice of a five year period is arbitrary and unwarranted.

Utilities note Staff to claim that: "Since the annual accruals can vary greatly from one year to the next, it is more appropriate to normalize the expense for ratemaking purposes." Staff Init. Br. at 32. Any reasonable review of the actual levels, the Utilities contend, shows Staff's claim to be incorrect.

Staff's exhibits (Staff Ex. 16.0, Sched. 16.2 P, p. 2, lines 1-5, and Sched. 16.2 N, p. 2, lines 1-5) show that the levels for Peoples Gas and North Shore for fiscal years 2002 through 2006 were as follows:

Injuries and Damages Accruals

	Peoples Gas	North Shore
FY 2002	$9,185,000	$1,940,000
FY 2003	$5,147,000	$279,000
FY 2004	$5,124,000	$371,000
FY 2005	$6,502,000	$415,000
FY 2006	$6,192,000	$477,000

It is obvious, the Utilities assert, that the levels here shown do not support "normalization". It is only and precisely with Staff's inclusion of fiscal year 2002 data that the results would yield a large variance. Further, while Staff would claim no showing that fiscal year 2002 is an "outlier," Staff Init. Br. at 33, the data above plainly refute that claim. As such, the Utilities argue, there is no valid factual basis for Staff's proposed disallowances.

Noting Staff to rely on the Ameren Order to supports its use of the five-year period, Utilities point out that Staff never did provide the data that was used in that case to determine that normalization was appropriate in the first place. Moreover, in that instance, the Commission approved the AG's proposed use of a five year "average" of the payouts, and not the complex formula Staff applied here. Had Staff used that methodology, the Utilities observe, its proposed disallowances only would be smaller, because Staff would arrive at a level of $5,443,200 for Peoples Gas, not $5,242,000, and $545,000 for North Shore, not $373,000. *See* Staff Ex. 16.0, Sched. 16.2 P, p. 2, line 6, column (c) (divide by 5) versus line 9, and Sched. 16.2 N, p. 2, line 6, column (c) (divide by 5) versus line 9. Utilities maintain, however, that Staff's proposed adjustments should be rejected in their entirety, because it could not be clearer that normalization is not warranted in the first place, and that there is no valid reason given for Staff's employment of a methodology different from more generally used methodologies (the results of which would increase, not decrease, the expense levels included in the revenue requirements).

Finally, the Utilities would note that Staff's position, calling for normalizing the level of injuries and damages expenses, is theoretically inconsistent with its calling for the use of an abnormally low test year value for collection agency fees, as is being considered in Section III(C)(2) of this Order.

(4) Commission Analysis and Conclusion

We see from the record that depending on the time periods selected for normalizing, the results will either be fairly representative or skewed. While this Commission has accepted 5-year averaging in other cases, this is obviously not a hard and fast rule. It is always necessary, when gathering any periods of data, to further apply sound and reasoned judgment. Here, we are not persuaded by the correctness of using 5 years of data for reasons that one of these years, i.e., 2002, is clearly and unmistakably different from the others. Further, we perceive that something is inherently wrong in the selection when the results change so drastically when either 3 or 4 year data is considered. So too, we are not convinced that Staff's normalization required the complex methodology that it applied especially where plain averaging has been utilized in past cases. And, we see that the use of averaging also would have produced different results. For all these reasons, and because we are not persuaded that normalization was ever required in this instance, we reject Staff's proposed adjustments.

In the final analysis, the Commission finds that North Shore and Peoples Gas used the correct levels of injuries and damages expenses in calculating their revenue requirements. North Shore appropriately used its unadjusted test year level. Peoples Gas appropriately used its test year level, adjusted for a highly unusual credit recorded in fiscal year 2006 relating to a major claim that occurred in fiscal year 2002. No adjustments need be made.

b) Incentive Compensation Expenses

(1) Peoples Gas & North Shore

Peoples Gas and North Shore seek to recover $5,376,000 and $576,000, respectively, of incentive compensation program costs in their revenue requirements. Pearce Dir., Staff Ex. 2.0, Scheds. 2.2P and 2.2N. All these costs, they maintain, are prudent and reasonable in amount.

The Utilities seek to recover costs associated with several specific programs within their incentive compensation plans. Those programs include: (1) the Team Incentive Award plan; (2) the Individual Performance Bonus plan; (3) the Short-term Incentive Compensation ("STIC") plan; (4) officers' incentive compensation and bonuses charged by Peoples Energy Corporation to Peoples Gas and North Shore; and (5) long-term incentives, such as restricted stock and performance shares, covered by the 2004 incentive compensation plan. The evidence regarding these plans, the Utilities assert, shows that the expenses should be allowed.

The TIA Plan

The 2006 Team Incentive Award ("TIA") plan applied to non-officer, non-union employees. NS-PGL Ex. JCH-1.0 at 4. The performance measures under the TIA plan were 55% "financial" and 45% "operational". Id. at 4-5. The "operational" performance measures consisted of a 25% weighting for controlling O&M expenses and a 20% weighting for customer satisfaction criteria (10% based on the number of calls to the Utilities' call centers and 10% based on the ranking of the Utilities' Gas Charges compared with those of six other Illinois utilities.) Id. The Utilities demonstrated, in

detail, that Staff's attempts to deny that 45% of the measures were operational are not correct, and Staff actually admitted that the Call Center metric benefits customers. NS-PGL Ex. JCH/FLV-2.0 at 5-7. Accordingly, while complete recovery of the entire $1,642,847 paid out, $1,502,584 by Peoples Gas and $140,253 by North Shore ($1,607,568 had been accrued, $1,465,444 by Peoples Gas and $142,124 by North Shore), under the TIA plan (NS-PGL Ex. LK-2.0 at 9 (dollar amounts)) is appropriate, at a minimum, Peoples Gas should recover the $1,009,240, and North Shore should recover the $94,024, that they paid out under the operational measures. NS-PGL Ex. JCH/FLV-2.0 at 7.

The IPB Plan

The 2006 Individual Performance Bonus ("IPB") plan also applied to non-officer, non-union employees. NS-PGL Ex. JCH-1.0 at 5. The performance measures under the IPB plan were not "financial", rather each division's senior management, with input from their managing staff, was responsible for calculating and awarding the IPB to their own employees, and, as the name of the plan indicates, the awards were based on individual performance. Id. at 5:95-103. Staff's unsupported speculation that the pool for this plan might somehow be "financial" was incorrect. NS-PGL Ex. JCH/FLV-2.0 at 9. The plan benefited customers by encouraging outstanding individual work performance. Id. NS-PGL Ex. JCH/FLV 2.2. Staff's objection that the Utilities did not establish specific dollar savings and other tangible benefits is not reasonable given that the pool and the awards are not tied to financial performance and the IPB awards went to 426 different employees in an average amount of $2,884.53. NS-PGL Ex. JCH/FLV-2.0 at 9-10. Accordingly, complete recovery of the entire $678,898 paid out, $625,791 by Peoples Gas and $53,107 by North Shore ($496,910 had been accrued, $464,408 by Peoples Gas and $32,502 by North Shore), under the IPB plan (NS-PGL Ex. LK-2.0 at 9 (dollar amounts)) is appropriate.

The STIC Plan

The 2006 STIC plan applied to senior management of Peoples Gas. NS-PGL Ex. JCH-1.0 at 6. The performance measures under the STIC plan were the same as under the TIA plan, discussed above. Id. at 6. There were no payouts as to fiscal year 2006, but that was for unusual reasons that are not expected to reoccur. Id. at 6. Accordingly, complete recovery of the entire $457,000 that was accrued, or, at a minimum, of the $306,953 that was accrued as to the operational measures, under the STIC plan (NS-PGL Ex. LK-2.0 at 9 (dollar amounts)), is appropriate.

The Affiliate Charges

The Peoples Energy Corporation charges for officers incentive compensation and bonuses to Peoples Gas and North Shore were generally based 37.5% on operational measures. NS-PGL EX. JCH-1.0 at 6. Accordingly, the entire $744,812 charged to Peoples Gas and the entire $165,811 charged to North Shore (Staff Ex. 2.0, Sched. 2.2P, p. 2, lines 12-13, and Sched. 2.2N, p. 2, line 12 (dollar amounts)) should be recovered or, at a minimum, 37.5% thereof.

Restricted Stock and Performance Shares

The restricted stock program was based on providing a competitive compensation package, not "financial" measures, while the performance shares program was based on "financial" measures. NS-PGL Ex. JCH-1.0 at 7. Accordingly, the entire $1,756,000 accrued (PGL only) (Staff Ex. 2.0, Sched. 2.2P at 2, lines 4-5 (dollar amount) should be recovered or, at a minimum, the amount of $1,529,000 as to the restricted stock program (Id. at line 4 (dollar amount)) should be allowed.

The Utilities contend that incentive compensation benefits customers through: increased customer satisfaction; improved service reliability; more efficient, lower cost operations that lead to lower rates over time when compared to less efficient operations; improved employee performance; enhanced ability to attract and to retain high-quality employees; and better employee productivity. In their view, these numerous benefits shown on record, satisfy any Commission requirement that incentive compensation not only be prudent and reasonable but benefit customers. By claiming that more is required in the way of specific dollar savings, Staff and GCI advance an unsupportable and inconsistent interpretation of the Commission's past tests. More egregiously, Utilities assert, their proposals would wrongly deny Peoples Gas and North Shore their right to recover all prudent and reasonable expenses. *See* Citizens 1995, 166 Ill. 2d at 121.

Further, the Utilities observe that the Commission has approved recovery of incentive compensation expenses in various other rate cases, including: In re Commonwealth Edison Co., Docket 05-0597, Order at 97 (July 26, 2006); In re Consumers Illinois Water Co., Docket 03-0403, Order at 14-15 (April 13, 2004); In re Illinois-American Water Co., Docket 02-0690, Order at 17-19 (August 12, 2003); and In re Commonwealth Edison Co., Docket 01-0423, Interim Order at 109-111 (April 1, 2002), and Order at 120-122 (March 28, 2003). The Utilities urge the Commission to do so here.

In the alternative, the Utilities maintain that the Commission should allow recovery of the specified operational and non-financial expenses, including, at a minimum: (1) Peoples Gas and North Shore should be allowed to recover $1,009,240 and $94,204, respectively, under the TIA plan; and (2) $625,791 and $53,107 under the IPB plan, respectively.

Incentive compensation, the Utilities assert, is a prudent expense. As their witness James Hoover explained, "[t]he Utilities compete in the labor market with other utilities and other businesses that offer incentive compensation.... [T]he programs are the product of careful decisions about what types and levels of incentive compensation are needed in order to attract and retain a sufficient, qualified, and motivated work force." NS-PGL Ex. JCH-1.0 at 3 & 8. Further, incentive compensation benefits a utility's customers "by making sure there are enough employees to perform needed work, by maintaining and improving the productivity and quality of work, and by reducing the expenses associated with recruiting and training new employees." Id. at 3-4. No witness, the Utilities note, has directly challenged this particular testimony (although two witnesses did claim that such customer benefits should be disregarded based on their

understanding of the way that Commission has previously approached to the subject of incentive compensation).

The record contains further evidence of more specific, tangible customer benefits, the Utilities argue. For example, in their surrebuttal testimony, witnesses Hoover and Volante set out that the incentive compensation programs were a contributing factor in Peoples Gas and North Shore's reduction of O&M expenses below target levels. NS-PGL Ex. JCH/FLV-2.0 at 6.

According to the Utilities, no witness has challenged Peoples Gas' and North Shore's total compensation to employees, or, in particular, the incentive compensation portions, as imprudent or excessive. No witness testified that their incentive compensation programs and payouts thereunder are not prudent and reasonable from the perspective of managing their human resources. NS-PGL Ex. JCH 1.0 at 4. Indeed, it is clear that under the Staff and GCI positions, the amounts of incentive compensation that they challenge would not be at issue if the Utilities had paid the exact same amounts in total compensation as base pay. *See, e.g.*, Tr., 1196-1200. In light of this testimony, the Utilities maintain that their incentive compensation costs merit full recovery through rates.

(2) AG

The AG points out that the Commission typically disallows incentive compensation from utility revenue requirements except in those instances where the utility has demonstrated that its incentive compensation plan reduced expenses and created greater efficiencies in operations. In this instance, the AG contends, neither Peoples Gas nor North Shore have presented testimony persuasive enough to satisfy this criterion. GCI Ex. 5.0 at 10. The AG points out that both Staff witness Bonita Pearce and GCI witness Effron have recommended removal of incentive compensation costs from the 2006 test year of each Company. Staff Ex. 1.40 at 4; GCI Ex. 2.0 at 25-26; GCI Ex. 4.0 at 11.

The AG observes the Utilities witness to have testified that these programs serve "to attract and retain a sufficient, qualified and motivated work force." Staff Ex. 1.40 at 3. According to the AG, however, nothing in Mr. Hoover's rebuttal and surrebuttal testimony shows how the programs either reduce expenses or create the efficiencies that the Commission requires to support rate recovery. The AG states that the Commission made clear these standards for recovery of incentive compensation in the recent Nicor rate case, Docket 04-0779, and reaffirmed them in the 2006 Ameren Order. The AG considers the Utilities' descriptions of their incentive compensation programs and their vague assertions that such programs benefit ratepayers, as being inadequate to demonstrate that the incentive compensation plans have reduced expenses and created greater efficiencies in operations. In the AG's view, the Utilities have not satisfied the well established standards for the recovery of incentive compensation in the cost of service set out in the orders here cited.

In other words, the AG argues, the Utilities have failed to demonstrate that their incentive compensation plan confers upon ratepayers specific dollar savings or other tangible benefits. Thus, the AG contends that the incentive compensation expense

should be eliminated from the cost of service. More precisely, Mr. Effron's recommendation that the incentive compensation expense be eliminated from the cost of service should be adopted, resulting in a reduction to Peoples Gas' test year operations and maintenance expense of $5,376,000, including the elimination of related payroll taxes. The reduction to North Shore's test year operations and maintenance expense is $576,000. GCI Ex. 5.0 at 11.

(3) Staff

Staff contends that none of the Utilities' incentive compensation costs should be reflected in rates. Staff Ex. 2.0 at 6–18 and Staff Ex. 14.0 at 3–20. Accordingly, Staff witness Pearce proposed adjustments to remove 100% of the costs of incentive compensation plans from operating expenses and rate base of North Shore and Peoples Gas. Staff Ex. 2.0, Schedules 2.2N and 2.2P, respectively. Staff's primary reason for its adjustment is that the incentive compensation plans are discretionary in nature and there has been no showing of demonstrated ratepayer benefit. Staff Ex. 14.0 at 4.

Staff notes, however, that if the Commission were determined to allow some portion of these expenses in rates, the least objectionable cost would be to allow costs related to that portion of the TIA Plan that is based on non-financial, i.e., operational measures that directly benefit ratepayers. In rebuttal testimony, Staff calculated an alternative for 10% cost recovery of the TIA Plan based on the number of calls to the call center component described by Utilities witness Hoover in his rebuttal testimony. Use of this methodology, Staff explains, would provide recovery in rates of $146,544 for Peoples Gas and $14,212 for North Shore Gas in 2006 test year operating expenses based on the TIA Plan expenses accrued for the test year. Id. at 19-20.

Further, and in response to the surrebuttal testimony of Utilities witnesses Hoover and Volante, Staff's calculated alternative to complete disallowance of all incentive compensation costs would be adjusted to $282,486 for Peoples Gas and $26,368 for North Shore (18.8% of actual payouts of $1,502,584 and $140,253 for Peoples Gas and North Shore, respectively), based on the final payout percentages and amounts awarded under the TIA Plan. North Shore/Peoples Gas Ex. JCH/FLV-2.0, lines 137-146. Staff's revised alternative is based on reduction of calls to the call center (the same methodology described in Staff's rebuttal testimony).

Staff does not believe that the Commission has ever approved recovery of incentive compensation costs on the basis of a utility's need to 'attract and retain a sufficient, qualified, and motivated work force', as it observes the Utilities to here assert. According to Staff, the only legitimate criterion for recovery of any portion of incentive compensation expense, based on prior Commission practices, is the demonstration of direct ratepayer benefits. As such, Staff sets out its arguments on each of the five Plans at issue.

In rebuttal testimony, Utilities witness Hoover asserted that the TIA Plan contained "non-financial" goals that directly benefit ratepayers such that 45% of the accrued costs of that plan should be recovered from ratepayers. In surrebuttal testimony, Mr. Hoover changed his methodology to assert that the percentage should

be based on the amounts actually paid out under the TIA Plan instead of amounts accrued, as reflected in the test year. He then recalculated the "non-financial" percentage of incentive compensation expense and asserted that 67.2%, not of 45% of the TIA Plan should be reflected in rates, based on actual amounts paid out for 2006. NS-PGL Ex. JCH/FLV-2.0 at 7. The percentage of 67.2% includes the operational measures of (1) controlling O & M expenses (48.4%), and (2) calls to call centers (18.8%). Staff rejects this final alternative proposal to complete recovery of incentive compensation costs. Regarding the 25% factor for controlling O & M expenses, Staff notes that the Commission previously found this type of criterion to benefit shareholders rather than ratepayers, as noted by Staff witness Pearce. Staff Ex. 2.0, lines 323 – 335. With respect to the percentage of the payout that is based on calls to the call center, Staff explains that it revised its alternative to reflect the actual payouts and percentages.

Regarding the costs of the STIC Plan, Staff does not consider any of these accruals to be recoverable since they are based on measurements that primarily benefit shareholders, not ratepayers. For example, Staff observes that the awards to senior management (Chairman, President, and CEO) are entirely based on Earnings Per Share ("EPS") and normalized operating income of Peoples Energy Corporation ("PEC"). Up to 50% of the awards to the remaining participants (the Plan only applies to officers) are based on EPS. The payment trigger for all STIC is the net income of PEC. In addition, Staff would note, STIC awards accrued during 2006 were not actually paid.

Under the Individual Performance Bonus Plan, Staff maintains that the bonus amounts are discretionary and not tied to any formula. NS-PGL Ex. JCH-1.0, lines 95–103. Staff observes Mr. Hoover to rationalize that since the awards were based on an employee's individual performance (instead of the financial performance of the Utilities) and because the pool from which these awards were paid was a fixed dollar amount, these awards were not tied to the financial performance of the Utilities. Staff notes, however, that these awards are discretionary, which means they are able to be discontinued at any time after the test year. Additionally, Staff notes that the Utilities have not demonstrated that such awards are based on specific dollar savings or other tangible benefits to ratepayers, as required by the Commission in numerous prior proceedings. Finally, Staff observes from a response to a Staff Data Request, that the IPB Plan was only in place for 2006, i.e., the test year, and not any other year in the previous five fiscal years. This raises Staff's concern that these plans are discretionary and may be changed or discontinued any time after the test year.

Staff points out that the Utilities failed to demonstrate any ratepayer benefits or cost savings that resulted from the other Plans, i.e., officers' bonuses and incentive compensation expenses charged to Peoples Gas by an affiliate, as well as the restricted stock and performance shares programs. According to Staff, the Utilities simply rely on the bare assertion that these plans are not based on "financial measures". NS-PGL Ex. JCH-1.0 at 6-8. As such, Staff maintains that these plans do not meet the criteria of cost savings and/or direct ratepayer benefit that the Commission has required in numerous prior rate cases. These plans, Staff contends, are based primarily on providing 'a competitive compensation package' and 'to attract and retain a qualified work force'. NS-PGL Ex. JCH-1.0 at 7-8.

Staff maintains its position that none of the costs of incentive compensation plans should be reflected in utility rates for the reasons set forth in Staff witness Pearce's direct testimony and rebuttal testimony, to wit:

1) the Plans are largely dependent upon financial goals of the Utilities that benefit shareholders but not ratepayers;

2) in the future, the goals in the Plans may not be met and thus the Utilities would incur no cost (i.e., the payment of future awards is discretionary, but costs would be recovered in rates regardless); and

3) prior Commission orders support the disallowance of incentive compensation in these circumstances (as described in items 1 and 2 above, absent a demonstration of direct ratepayer benefits or savings.

Staff notes that several of the plans at issue contain a variety of performance measurement objectives. Staff is concerned that, for the future, management may assign different weights to these factors as they see fit. In other words, Staff believes that there is no guarantee that changes to the plans might occur going forward, and these might not provide any direct ratepayer benefit or savings. Staff Ex. 14.0 at 10. Accordingly, Staff urges the Commission to deny recovery of all incentive compensation costs in the instant proceeding.

(4) City-CUB

It is established policy, the City-CUB assert, that the Commission will allow the expense only if the utility has demonstrated that its incentive compensation plan has provided a tangible, quantified benefit to ratepayers, *i.e.,* reduced expenses and created greater efficiencies in operations. These requirements, they contend, were plainly stated in the order for the Nicor Gas rate case, Docket No. 04-0779. Further, the Commission reiterated its standards for the recovery of incentive compensation in the Ameren Order at 72.

Here, the City-CUB contend, the Utilities have failed to demonstrate their incentive compensation plan confers upon ratepayers specific dollar savings or other tangible benefits. Thus, they argue, the Utilities' *pro forma* operation and maintenance expenses should be adjusted to eliminate the incentive compensation expenses incurred in the test year. City-CUB explain that the reduction to North Shore test year operation and maintenance to eliminate incentive compensation is $576,000, and the reduction to Peoples Gas test year operation and maintenance to eliminate incentive compensation is $5,376,000, including the elimination of related payroll taxes. GCI Ex. 5.0 at 11.

(5) North Shore/Peoples Gas Response

Peoples Gas and North Shore seek to recover $5,376,000 and $576,000, respectively, of incentive compensation program costs (gross amounts, including capitalized expense amounts and operating expenses (including associated payroll taxes in Taxes Other Than Income Taxes)) in their revenue requirements. Staff Ex. 2.0, Scheds. 2.2P and 2.2N. These costs are prudent and reasonable in amount, they assert, and the Utilities should be allowed to recover them. Staff and GCI propose to

disallow all of these costs. But, the Utilities argue, their proposals are erroneous and unreasonable, and should be rejected.

In the alternative, at a minimum, Peoples Gas and North Shore should be allowed to recover (1) $1,009,240 and $94,204, respectively, under the Team Incentive Award ("TIA") plan; and (2) $625,791 and $53,107, respectively, under the Individual Performance Bonus ("IPB") plan.

Like other large Utilities, Peoples Gas and North Shore include incentive compensation as part of their overall employee compensation packages. The Utilities maintain that they must offer incentive compensation in order to provide the competitive compensation package necessary to attract and to retain high-quality employees. It is on record that: "The Utilities and other large businesses seek to design employee compensation in order to attract and retain a sufficient, qualified, and motivated work force. Incentive compensation programs are a common method to help achieve those objectives." NS-PGL Ex. JCH-1.0 at 3. No witness, the Utilities note, has challenged this testimony.

Incentive compensation programs, the Utilities argue, were a contributing factor in Peoples Gas and North Shore's reduction of O&M expenses below target levels. NS-PGL Ex. JCH/FLV-2.0 at 6. They observe the Commission to have recognized that incentive compensation programs that reward employees for lowering operating costs benefit customers. *See* In re Commonwealth Edison Co., Docket 01-0423, Order at 129 (March 28, 2003); In re Consumers Illinois Water Co., Docket 03-0403 Order at 14-15 (April 13, 2004); In re Northern Illinois Gas Co., Docket 95-0219, Order at 27 (April 3, 1996). While Staff suggests that controlling and reducing costs do not count as benefiting customers, that is illogical and is inconsistent with the Commission orders upon which Staff relies. NS-PGL Ex. JCH/FLV-2.0 at 4-5. In the end too, Staff admits that measures tied to customer satisfaction directly benefit ratepayers. Staff Ex. 2.0 at 19.

According to the Utilities, incentive compensation plainly qualifies as a prudent expense. They assert that the programs offered are "the product of careful decisions about what types and levels of incentive compensation are needed in order to attract and retain a sufficient, qualified, and motivated work force." NS-PGL Ex. JCH-1.0 at 3 & 8. Further, incentive compensation for that same reason benefits a utility's customers: It is of record that a utility's attracting and retaining a sufficient, qualified, and motivated work force "benefits its customers by making sure there are enough employees to perform needed work, by maintaining and improving the productivity and quality of work, and by reducing the expenses associated with recruiting and training new employees." Id. at 3. Again, the Utilities point out, no witness challenged this testimony.

No witness, the Utilities observe, challenged Peoples Gas' and North Shore's total compensation to employees, or, in particular, the incentive compensation portions, as imprudent or excessive. No witness testified that their incentive compensation programs and payouts thereunder are not prudent and reasonable from the perspective of managing their human resources. NS-PGL Ex. JCH 1.0 at 4. Indeed, the Utilities note that it is clear from the Staff and GCI positions, that the amounts of incentive compensation that they here contest, would not be challenged if the Utilities had paid

the exact same amounts of total compensation but had made the incentive compensation amounts part of base pay. *See, e.g.*, Tr. at 1196. In light of this testimony, the Utilities' maintain, their challenged incentive compensation costs merit full recovery through rates.

The Utilities maintain that incentive compensation benefits customers through: (a) increased customer satisfaction; (b) improved service reliability; (c) more efficient, lower cost operations that lead to lower rates over time when compared to less efficient operations; (d) improved employee performance; (e) enhanced ability to attract and to retain high-quality employees; and (f) better employee productivity. These numerous benefits, the Utilities assert, satisfy any Commission requirement that incentive compensation not only be prudent and reasonable but benefit customers. By claiming that more is required in the way of specific dollar savings, Staff and GCI advance an unsupportable and inconsistent interpretation of the Commission's past tests. And, their proposals would wrongly deny Peoples Gas and North Shore their right to recover all prudent and reasonable expenses. *See* Citizens 1995, 166 Ill. 2d at 121.

Additionally, the Utilities observe, there is nothing to suggest that they will not incur incentive compensation expenses going forward. Although there were no payouts during fiscal year 2006 under the STIC plan, that was for unusual reasons that are not expected to reoccur. NS-PGL Ex. JCH-1.0 at 6. Thus, the Utilities consider Staff's and GCI's concerns on this point are illusory and unsupported by the record.

Further, Staff and GCI propose to deny Peoples Gas and North Shore recovery of the incentive compensation portions of their total compensation expense without disputing that the Utilities' total compensation and the incentive compensation portions are prudent or reasonable in amount. Staff Ex. 2.0 at 6-18; GCI Ex. 2.0 at 25-26. The Utilities note GCI witness Effron to acknowledge that his testimony did not even address whether the Utilities' incentive compensation programs are prudent. Tr. at 1196. He further indicated that under his approach (which is the same as Staff's), it would not matter whether the Utilities' incentive compensation program helped to attract and retain the most qualified employees. Tr. at 1203. And, Staff witness Pearce made a similar admission. Staff Ex. 14.0 at 6. In the Utilities view, the proposed disallowances thus contravene the established principle that rates "must allow the utility to recover costs prudently and reasonably incurred." Citizens Utility Board v. Illinois Commerce Comm'n, 166 Ill. 2d 111, 121 (1995).

While Staff and GCI cite to certain Commission orders where recovery for incentive compensation was disallowed, the Utilities point out that the Commission has approved recovery of incentive compensation expenses in various other rate cases, including: In re Commonwealth Edison Co., Docket 05-0597, Order at 97 (July 26, 2006); In re Consumers Illinois Water Co., Docket 03-0403, Order at 14-15 (April 13, 2004); In re Illinois-American Water Co., Docket 02-0690, Order at 17-19 (August 12, 2003); and In re Commonwealth Edison Co., Docket 01-0423, Interim Order at 109-111 (April 1, 2002), and Order at 120-122 (March 28, 2003). The Utilities ask the Commission to do so here.

(6) Commission Analysis and Conclusion.

Before us on this issue are two conflicting views. While the Utilities assert that all parts of their incentive programs meet the standard for recovery, Staff, CUB and the AG would generally argue that none of these plans satisfy the test. As such, the Commission is put to the task of examining the record and applying its reasoned judgment informed by all of the relevant circumstances.

The record shows that there are as many instances where the Commission has approved incentive compensation as there are cases where such an expense has been denied. The main and guiding criterion is that the expense be prudent, reasonable and operate in a way to benefit the utility's customers. It is in this light that we consider the particulars of the programs, the amounts paid out, to whom and why, and what this all means to the Utilities' customers.

We agree with Staff that three of the five plans (STIC, Affiliate Charges, Restricted Stock & Performance Shares) fail to demonstrate the cost saving or other direct ratepayer benefit that we require. The remaining two plans, however, bring different concepts into focus.

Being a large utility means that management depends on the dutiful work performance of its employees. To motivate and maintain high standards, a utility may reasonably offer incentive compensation as the best way to match both employer and employee interests and to ensure quality work performance. And, when matters of customer service, customer satisfaction, the reduction of operating expenses, and the like is at hand, it is incumbent upon the Commission to take a close and considered view. It is on this basis that we turn our attention to the Utilities' non-executive TIA and IPB Plans.

The TIA Plan

This Plan applies to non-officer employees. As to its particulars, the Utilities' surrebuttal testimony effectively disputes Staff's claim that controlling O & M expenses should not count. It further shows that in the 2006 test year the aggregate actual O & M expenses were about $11 million below budget. Under the Plan, 25% of the measures were based on controlling these very expenses and we consider this as beneficial to ratepayers.

We further see that another 10% of the measures are tied to the number of phone calls made to the call centers. Even Staff recognizes the value of motivating this work. As such, Ms. Pearce admits that measures tied to customer satisfaction directly benefit ratepayers. Staff Ex. 2.0 at 19.

Further there is a measure of 10% associated with gas expenses and Gas Charges that we also believe should be counted. Finally, other unchallenged evidence of record confirms that 67.2% of the total payments were based on measures for controlling O & M expenses (48.4%) and call centers (18.8%). It is on this basis, that the Utilities derive their alternative proposal.

IPB Plan

The IPB plan is also a non-executive program that is aimed at encouraging outstanding individual work. It is uncontested that the awards are not based on financial performances. The record shows that the IPB awards went to 426 different employees, and were paid out in an average amount of $2,884.53. Taken together, the goal of the plan, the large pool of potential awardees and the wide-reaching motivational impact, make it more likely than not, that ratepayers will benefit from the race to excellence.

We do not share Staff's concerns as to possible changes or discontinuances of these Plans. The Commission finds that Peoples Gas and North Shore have demonstrated a steadfast commitment to incentive compensation in that they recognize the value, if not the necessity, of providing incentive compensation going forward. We would expect that if changes were to occur, these would equally go to the benefit of ratepayers.

In the final analysis, the Commission concludes that Peoples Gas and North Shore should be allowed to recover $1,009,240 for Peoples Gas, and $94,024 for North Shore for costs associated with the operational measures of the "TIA" plan.

Further, we allow the amounts of $625,791 for Peoples Gas, and $53,107 for North Shore, under the "IPB" plan, which is tied to individual performance and not to any financial measures. These costs are reasonable and prudent, and we perceive them to benefit the Utilities' customers. Together with all of the exceptions arguments, the Commission further rejects the GCI's alternative proposal on exceptions to have the Utilities' recovering under the IPB Plan be limited to the amounts accrued.

1. Invested Capital Taxes

a) North Shore / Peoples Gas

Staff and the Utilities agree that invested capital taxes need to be recalculated based on the final approved rate increases (the increases in base rate revenues) when setting the Utilities' final approved revenue requirements, and they agree over how to perform those calculations. NS-PGL Init. Br. at 54-55; Staff Init. Br. at 40.

The Utilities believe that, apart from an entirely speculative objection on the part of GCI, there is no dispute that invested capital taxes need to be recalculated based on the final approved rate increases (the increases in base rate revenues) when setting the Utilities' final approved revenue requirements, and that there is no dispute over how to perform those calculations. *E.g.*, NS-PGL Ex. SF-2.0 at 15; NS-PGL Exs. SF-2.13P and 2.13N; Staff Cross Exs. 1 and 2 (Fiorella).

b) City-CUB and the AG.

(The GCI parties rely on the same evidence and raise the same points in their respective arguments on brief. Thus, we consider them jointly).

The GCI parties observe that the Utilities adjusted the invested capital tax to recognize the increased operating income that will result from the proposed increased rates in this docket under the theory that an increase in operating income will in turn

result in an increase to retained earnings and total capitalization, which is the base for the invested capital tax. GCI Ex. 2.0 at 34, citing PGL Ex. SF-1.0 at 24-25; NS Ex. SF-1.0 at 23. They point to the testimony of their witness Effron and his statement that these adjustments are inappropriate. They further note that Mr. Effron gave two reasons why the adjustments should be eliminated. GCI Ex. 2.0 at 34.

First, Mr. Effron observed that the Utilities have assumed, for purposes of this adjustment, that their entire rate increase requests would be approved by the Commission. Based on his experience, testifying in Illinois as well as other jurisdictions, Mr. Effron considered that such a scenario to be unlikely. Id. at 35. Second, he noted that the Utilities had not established with any reasonable degree of certainty that an increase to operating income will lead to an equal increase to retained earnings and capitalization. Id. For example, he indicated that an increase to operating income resulting from this case could lead to an increase in shareholder dividends. Id. And, to the extent that any additional earnings are paid out in dividends, there will be no increase to retained earnings as a result of the increase in operating income. Id.

The effect of Mr. Effron's adjustment, the GCI parties explain, is to reduce Peoples' pro forma taxes other than income taxes by $814,000 and North Shore's pro forma taxes other than income taxes by $50,000. GCI Ex. 2.0 at 35; Schedule C-4.[16] They propose that these adjustments should be adopted by the Commission.

c) Staff

Staff observes the Utilities to propose that the pro forma invested capital taxes ("ICT") in these cases is a derivative adjustment, to be calculated based on the approved additional operating income multiplied by the statutory rate of 0.8%. Staff Cross Ex. 1 and 2 (Fiorella). The Utilities contend that this approach is correct since the tax, which is based upon the Utilities' capital structure, was calculated based on the Company's pro forma 56/44 capital structure being maintained throughout the period of calculation. The Utilities maintain that application of this capital structure to the entire year's results contains an inherent dividend policy of maintaining the pro forma capital structure at all times, and thus explicit modeling of the dividend under these conditions would lead to the same results as already provided. Id.

Based on this evidence, Staff's Appendices A and B to this brief, pages 9 and 8 respectively for Peoples Gas and North Shore, contain updated calculations of the pro forma ICT adjustments. Staff agrees that this is a derivative adjustment and should be updated for the Commission's final conclusions in these cases. Tr. at 1123.

Staff maintains that the GCI's position and its opposition to the adjustment lacks merit. At the outset, Staff notes, GCI's first objection is that the Utilities' adjustments are based on receiving their entire rate increase request. AG Init. Br. at 25; City-CUB Init. Br. at 21-22. The Utilities have agreed, though, to limit and adjust the increase for ICT

[16] Mr. Effron's adjustment to the Utilities' pro forma expenses reflects the elimination of the adjustments as originally proposed by the Utilities rather than the amounts in the subsequent revised filings. He eliminated those original adjustments because those are the amounts included in the Utilities' pro forma statements of operating income used as the starting points in his analysis. GCI Ex. 2.0 at 35.

to the increase approved in the final Commission order. NS-PGL Init. Br. at 54. Therefore, GCI's objection based on this point is moot.

Staff observes that the GCI's second objection is related to its belief that the increase in income could be paid out in dividends. AG Init. Br. at. 25. According to Staff, however, this argument is contradicted by the record evidence indicating that the Utilities' ICT adjustment calculation is based on the Utilities maintaining their current capital structures, which reflects an inherent dividend policy of maintaining the pro forma capital structure at all times. Staff Init. Br. at 40; Staff Cross Ex. 2 (Fiorella). In Staff's view, thus, GCI is incorrect to argue that the Utilities have presented no evidence regarding their dividend policy; rather, GCI has chosen to reject or ignore it. As such, Staff asserts, GCI's position warrants rejection. City-CUB Init. Br. at 21.

Staff urges the Commission to calculate the final level of ICT, in the manner shown by Staff in Appendix A and B Corrected to its Initial Brief, at pages 9 and 8, respectively, based on the final approved rate increases or decreases.

d) North Shore / Peoples Gas Response

The Utilities note that GCI witness Effron proposed, on two grounds, to disallow the Utilities' *pro forma* adjustments reflecting the impacts on ICT of their proposed rate increases. First, he testified that the amounts for ICT included in the Utilities' proposed revenue requirements reflect the Utilities' proposed rate increases. *See* AG Init. Br. at 17; City-CUB Init. Br. at 21. In the Utilities view, this is a frivolous complaint. ICT are a derivative adjustment. Staff Init. Br. at 40. The correct way for a party to calculate a derivative adjustment is to start with its proposed positions on the merits of the relevant issues. The Utilities and Staff have made clear that the final amounts need to be recalculated based on the final approved rate increases.

The second ground, the Utilities observe, is nothing more than Mr. Effron's simple speculation that "it is entirely possible that an increase to operating income would lead to an increase in dividends. To the extent that any additional earnings are paid out in dividends, there will be no increase to retained earnings as a result of the increase in operating income." GCI Ex. 2.0 at 35. The Utilities point out that Mr. Effron provides no factual basis for his speculation, and, they assert, there is none. So too, they argue, Mr. Effron's proposal to deny recovery of ICT simply on the basis of such speculation is improper and cannot be considered by the Commission. *E.g.,* Ameropan Oil Corp. v. ICC, 298 Ill. App. 3d 341, 348 (1st Dist. 1998) ("speculation has no place in the ICC's decision or in our review of it."); Allied Delivery System. Inc. v. Illinois Commerce Comm'n, 93 Ill. App. 3d 656, 667 (1st Dist. 1981) ("The speculation indulged in by the Commission is clearly an unsatisfactory and unacceptable basis for its decision."); In re Commonwealth Edison Co., Docket 99-0117, Order at 105 (where the Commission states "we will not make an adjustment that is speculative"). (August 25, 1999).

The Utilities' assert that GCI's rank speculation about increases in dividends that might affect these taxes is unwarranted. The Utilities' proposed capital structure is uncontested. NS-PGL Init. Br. at 61. Thus, calculating these taxes based on different assumptions about dividends is not required. *See, e.g.*, Staff Cross Ex. 2 (Fiorella).

The Commission should calculate the final level of these taxes, in the manner which the Utilities and Staff agree is correct, based on the final approved rate increases.

e) Commission Analysis and Conclusion

The Commission accepts Staff's and the Utilities' proposal regarding the calculation of invested capital taxes. We are not persuaded by the bases for the GCI's proposed disallowances. There is no factual matter in dispute. In the end, there is no evidence in the record to support GCI's suggestion that an increase to operating income could lead to an increase in dividends. Nothing presented in the City-CUB's exceptions brief is persuasive on the matter.

2. Adjustment to Remove Non-Base Rate Revenues and Expenses (Schedule Presentation Issue)

Staff proposes to remove non-base rate revenues and expenses in presenting the Utilities' approved operating income statement. Staff emphasizes that this is a presentation issue, not a substantive proposal. The Utilities do not oppose this proposal, provided that it is only a presentation issue, and is implemented correctly. The Commission has considered Staff's proposal in preparing the applicable Schedules in the Appendix to this Order, and has formulated these Schedules as suggested by Staff.

D. Derivative Adjustments from Uncontested and Contested Issues

Various of the proposed rate base and operating expenses adjustments, when their full impacts are calculated, have derivative impacts on depreciation expenses, taxes other than income taxes, and/or income taxes, as shown in the Utilities', Staff's and GCI's respective Schedules, but no party has proposed any independent adjustments to these items. Accordingly, this Order, as to the foregoing items, need only make derivative calculations reflecting the approved adjustments.

E. Overall Conclusion on Operating Expense Statements

1. Peoples Gas

Based on the gas utility operating expense statement as originally proposed by Peoples Gas and the adjustments to operating revenues and expenses as summarized above, the total gas utility operating expenses for Peoples Gas approved for purposes of this proceeding are $365,321,000. The operating income statement may be summarized as follows:

Peoples Gas Operating Statement (in thousands)

Description	Approved Operating Statement
	$
Base Rate Revenues	440,305
PGA Revenues	-
Coal Tar Revenues	-
Other Revenues	15,688
Total Operating Revenue	455,993
Uncollectibles Expense	39,155
Cost of Gas	-
Other Production	557
Distribution	61,846
Customer Accounts	35,996
Customer Service and Informational Services	363
Sales	1,355
Administrative and General	95,884
Depreciation and Amortization	59,203
Storage	9,993
Transmission	2,568
Taxes Other than Income	18,515
Total Operating Expense Before Income Taxes	325,435
State Income Tax	10,013
Federal Income Tax	61,236
Deferred Taxes and ITCs Net	(31,363)
Total Operating Expenses	365,321
	$
NET OPERATING INCOME	90,672

The development of the overall gas utility operating expenses adopted for Peoples Gas, for purposes of this proceeding, are shown in Appendices A and B, respectively, to this Order.

2. North Shore

Based on the gas utility operating expense statement as originally proposed by North Shore and the adjustments to operating revenues and expenses as summarized

above, the total gas utility operating expenses for North Shore approved for purposes of this proceeding are $48,619,000. The operating income statement may be summarized as follows:

North Shore Operating Statement (in thousands)

Description	Approved Operating Statement
	$
Base Rate Revenues	60,978
PGA Revenues	-
Coal Tar Revenues	-
Other Revenues	1,639
Total Operating Revenue	62,617
Uncollectibles Expense	1,975
Cost of Gas	-
Other Production	170
Distribution	7,615
Customer Accounts	6,308
Customer Service and Informational Services	40
Sales	35
Administrative and General	18,523
Depreciation and Amortization	6,094
Storage	-
Transmission	95
Taxes Other than Income	2,034
Total Operating Expense Before Income Taxes	42,889
State Income Tax	9
Federal Income Tax	2,224
Deferred Taxes and ITCs Net	3,497
Total Operating Expenses	48,619
	$
NET OPERATING INCOME	13,998

The development of the overall gas utility operating expenses adopted for North Shore, for purposes of this proceeding, are shown in Appendices A and B, respectively, to this Order.

IV. RATE OF RETURN

A. Capital Structure

On September 30, 2006, the actual capital structure of North Shore was comprised of 40% long-term debt and 60% common equity and the actual capital structure of Peoples Gas was comprised of 43% long-term debt and 57% common equity. Staff Init. Br. at 41. For purposes of establishing rates in this proceeding, North Shore and Peoples Gas each propose imputed capital structures comprised of 44% long-term debt and 56% common equity. PGL-NS Init. Br. at 61.

Staff recommends utilizing the imputed capital structures proposed by North Shore and Peoples Gas. Staff, however, argues that under no circumstances should the Commission accept the Companies' proposed capital structures without also accepting Staff's proposed adjustments to the Companies' costs of common equity and debt.

The City-CUB witness incorporated North Shore's and Peoples Gas' proposed imputed capital structures in his calculation of the overall cost of capital. NS-PGL Init. Br. at 61.

The Commission has reviewed the record of this proceeding and finds that for purposes of establishing rates in this proceeding, a capital structure that is comprised of 44% long-term debt and 56% common equity should be used for both North Shore and Peoples Gas.

B. Cost of Long-Term Debt

1. Peoples Gas

There are no disputes concerning the cost of long-term debt. Peoples Gas and Staff agree that the appropriate cost of long-term debt to use for Peoples Gas in this proceeding is 4.67%. They also agree that certain adjustments to the actual embedded cost of debt are necessary to remove the incremental risk or increased cost of capital resulting from Peoples Gas' affiliation with unregulated or nonutility companies. Such adjustments are mandated by Section 9-230 of the Act as explained in Illinois Bell Telephone Co. vs. Illinois Commerce Commission, 283 Ill. App. 3d 188, 207 (1996).

Having reviewed the record here, we find that 4.67% is the cost of Peoples Gas' long-term debt for purposes of establishing rates in this proceeding, consistent with the requirements of Section 9-230.

2. North Shore

Similarly, there are no disputed issues and North Shore and Staff agree that the appropriate cost of North Shore's long term debt for this proceeding is 5.39%. The Commission has reviewed the record and finds that, for purposes of establishing rates in this proceeding, 5.39% is North Shores's cost of long-term debt, consistent with the requirements of Section 9-230 of the Act.

C. Cost of Common Equity

1. North Shore's and Peoples Gas' Position

Utilities witness Moul presented three market measures of the Utilities' cost of equity using the Discounted Cash Flow model ("DCF"), Capital Asset Pricing Model ("CAPM") and Risk Premium model. The Utilities state that because their stock is not publicly traded, the models must be applied to a proxy group of publicly traded natural gas utilities with risk profiles similar to the Utilities. NS-PGL Init. Br. at 66. For his proxy group, Mr. Moul's DCF analysis produced an estimate of 9.72%; his CAPM analysis produced results of 12.04%; and his risk premium analysis produced results of 11.44%. NS-PGL Ex. PRM-1.0 at 3. A simple arithmetic average of these three results produced a cost of equity estimate of 11.06%, which Mr. Moul believes to be a reasonable cost of equity for the Utilities and consistent with a comparable earnings analysis he performed to verify the reasonableness of his approach. Id. at 3-4.

a) DCF

In his DCF analysis, Mr. Moul used a quarterly version of the model. He estimated dividend yield by calculating the six-month average dividend yield of the utility sample, adjusting the average with what he describes as three generally accepted methods to reflect investors' expected cash flows, and then averaging the three adjusted values. In order to determine the investor expected growth rate, he evaluated an array of historical and forecast growth data from sources that he says are publicly available to, and relied upon by, investors and analysts. He focused on forecasts of earnings per share growth because empirical evidence supports it and because that is where investors actually place their greatest emphasis. He selected 5.00%, the approximate mid-point of the forecasts. Mr. Moul applied a financial leverage adjustment to his DCF result because DCF results are based on market prices of stock, which, according to Mr. Moul, imply a capital structure with more equity and less financial risk, but are applied to utility book values, which imply a capital structure with less equity and more financial risk. NS-PGL Init. Br. at 65-66.

The Utilities deny the criticism that Mr. Moul's DCF dividend yield was based on historical yields. Rather, they say he adjusted the six-month average yield of the utility sample "to reflect the prospective nature of the dividend payments, i.e., the higher expected dividends for the future rather than the recent dividend payment annualized." Id. at 66. Additionally, the Utilities state that although Mr. Moul reviewed historical data in considering the appropriate growth rate, he based his input on a mid-point of earnings per share forecasts. Id. at 66-67.

In response to Staff's objection to the use of an average of stock prices in the DCF model, the Utilities allege that Ms. Kight-Garlisch assumes a stock market with perfect efficiency that reflects the most recently available information each day. The Utilities aver that no evidence supports that hypothesis. The Utilities assert that a single day's price can produce an anomalous outcome because of the vagaries of the market. The Utilities claim that the short-term inefficiencies in stock prices are magnified when only a spot price is considered in the DCF return. Id. at 67.

The Utilities argue that because of these inefficiencies, analysts commonly use a six-month average dividend yield in the DCF model. According to the Utilities, that average provides a more representative estimate, adds stability to the result, better fits the long-term view of public utility rate-setting, and is more appropriate when rates are set for one or more future years. Id. at 68. The Utilities note City-CUB's assertion that an historical average ensures that the prices used in the DCF reflect all available information contained within the stock price. Id. (citing City-CUB Ex. 2.1). The Utilities maintain that rate-making is intended to set a return level appropriate for the period in which the rates will be in effect and the use of a single-day stock price can accomplish this objective only by coincidence. Id.

The Utilities further contend that thorough real-world investors do not purchase and sell stocks based exclusively on current prices, but also assess available historical and forecast information. The Utilities request that we reconsider our general concerns about the applicability of historical data in the market return models. In particular, they urge consideration of: 1) the lack of empirical foundation for the use of single-day spot data, which assumes a non-existent level of market efficiency; 2) the arbitrariness of setting returns based on "current" data that are nine months old; 3) what investors do in the real world, which is evaluate a stock's historical and forecasted performance in relation to its current price; and 4) the use of historical data in the DCF model, limited to the dividend yield, and adjusted to make it forward-looking. Id. at 69.

In addition to the overall concern with using a single day's data point in Staff's DCF analysis, the Utilities argue that anomalies in Staff's DCF results call into question the usefulness of Staff's DCF analysis in setting cost of capital in this case. The Utilities point out that the DCF results of three of the sample companies are below or too close to the cost of debt to measure the cost of equity reliably. The Utilities further observe that Staff's DCF analysis yielded a 5.91% ROE for Nicor, which they contend cannot be correct given the 10.51% ROE authorized by the Commission in North Illinois Gas Company's recent rate case. Petitioners also question NICOR's beta that emerged from Staff's DCF analysis. Moul Reb. NS-PGL Ex. PRM 2.0, 12-13.

According to the Utilities, the DCF model underestimates investor-required returns when a utility's stock prices diverge significantly from its book value. This occurs, the Utilities argue, because the investor-required return produced by the DCF model, which is related to the market value of common stock, is applied to the utility's book value capitalization in ratemaking. NS-PGL Init. Br. at 70.

Using formulas developed by Modigliani and Miller, Mr. Moul calculated a financial leverage adjustment of 52 basis points for this case. Id. As for Staff's objection that this adjustment has no basis in financial theory, the Utilities observe that Staff's own witness cites Modigliani's and Miller's conclusion that common equity costs are affected by debt leverage (to justify Staff's "credit quality risk" adjustment)

The Utilities charge that City-CUB witness Thomas actually wants commissions to regulate utility rates so that their stock prices always equal book value. They say that utility stock prices have been above book value for most of the past 50 years, yet commissions granted rate increases throughout this period. It is not conceivable, the Utilities maintain, that so many commissions have been so wrong for so long. Id. at 72.

They stress that the Pennsylvania Public Utility Commission has endorsed a financial leverage adjustment to the DCF model. Id. at 70.

The Utilities acknowledge past Commission decisions rejecting the financial leverage adjustment to DCF results, and they say they are not proposing to change this practice. Rather, in developing the market-required return, the Utilities urge us to take the increased financial risk of the book value capital structure into account when using the market-required rate of return on common equity. They request that we reconsider the financial risk adjustment, its theoretical underpinnings, and the evidence in this record that applying the DCF market results to book value capitalization will underestimate the investor's required return. Id. at 73.

Regarding growth rates used in the DCF model, the Utilities challenge City-CUB's claims that analyst forecasts are upwardly biased and that internal growth rates are better for calculating DCF growth rate. The Utilities say that concerns about analysts' conflicts of interest were resolved years ago by separating the research and investment banking services provided by Wall Street firms. They also allege that the studies City-CUB cite tend to report generalized findings and do not specifically suggest that utility growth rates are overstated relative to achieved growth. They further assert that the relationship of analyst growth forecasts to achieved growth is irrelevant to determining investors' true growth expectations. Id. at 74.

Moreover, the Utilities argue that internal growth rates measure the growth in the book value per share of a company, but book value also changes through the sale and repurchase of shares of stock. Book value per share, the Utilities contend, is not a correct focus of the DCF growth rate because stock does not trade at a constant market-to-book multiple. Id.

Mr. Moul states that the results of analytic models should be reviewed for fundamental reasonableness. Mr. Moul observed that three of Ms. Kight-Garlisch's DCF results for utilities in the sample approached and even fell short of the cost of debt. Such results, the Utilities argue, indicate that something seriously is wrong with Ms. Kight-Garlisch's application of the DCF model in this case. Id. at 75.

b) CAPM

The CAPM model determines an expected rate of return on a security by adding to the risk-free rate of return a risk premium that is proportional to the non-diversifiable, or systematic, risk of the security. This model requires three inputs to compute the cost of equity: (1) the risk-free rate of return; (2) a "beta" measure of systematic risk; and (3) the market risk premium derived from the total return on the market for equities minus the risk-free rate of return.

For the risk-free rate of return, Mr. Moul used historical and forecasted yields on 20-year Treasury bonds. He says long-term government securities are appropriate for the long-term horizon of utility investments. He selected a return, 5.25%, within the range of those yields. Ms. Kight-Garlisch relies on *short* term Treasury bills, but the Utilities aver that it makes little difference in this case due to the flat yield curve between long- and short-term Treasuries. NS-PGL Init. Br. at 79.

For the beta measurement of systematic risk, he used the average Value Line beta for his utility sample, adjusted to reflect the utility's book value capital structure used in rate-making. Mr. Moul believes Value Line betas cannot be used without adjustments in the CAPM, except when they are applied to a capital structure measured with market values. To develop a CAPM cost rate applicable to a book value capital structure, he unleveraged and re-leveraged the Value Line betas for the common equity ratios using book values. He likens this is to the financial leverage adjustment he made in his DCF model. His "leveraged" beta was 1.00 for the utility sample (the average Value Line beta for his gas sample is 0.84), indicating that the group's systematic risk with book value capital structures is equal to the market's risk in general. In response to City-CUB's charge that the adjusted betas are biased, the Utilities counter that the Commission previously ruled that using unadjusted betas cause a downward bias in cost of common equity estimates. Id. at 80.

Mr. Moul developed the market premium of 6.60% by averaging historical and forecasted equity market performance derived from data sources routinely used by investors and analysts. For the forecast data, Mr. Moul specifically relied on the Value Line forecasts of capital appreciation and the dividend yield on 1,700 stocks. With these inputs, he calculated a CAPM cost of equity of 12.04%. Id. at 76-77)

c) Risk Premium

The Risk Premium model measures the cost of equity by determining the degree to which equity is more risky than corporate debt, and adding the compensation associated with that additional risk - the equity risk premium - to the interest rate on long-term debt. The Utilities acknowledge that this model has its limitations because analysts often cannot agree on the future cost of corporate debt and the measurement of the equity risk premium. NS-PGL Init. Br. at 81.

Mr. Moul estimated a 6.25% prospective yield on A-rated utility bonds, based on recent historical data and forecasts published by Blue Chip, which the Utilities claim is a widely utilized source that contains consensus forecasts of a variety of interest rates compiled from a panel of banking, brokerage, and investment advisory services. For the equity risk premium, Mr. Moul compared market returns on utility stocks and bonds over various historical periods using the S&P Public Utility Index, and arrived at a 5.00% premium that includes an adjustment for the lower overall risk of the utility sample compared to the S&P index. Mr. Moul's Risk Premium model yields a rate of return for the Utilities of 11.44%, which falls between his DCF (9.53%) and CAPM (12.04%) results. Id. at 81-82.

Staff challenged Mr. Moul's use of historical public utility bond yields in his risk premium analysis because he did not demonstrate that they are equivalent to the A-rated bond yield, but the Utilities believe this would make no difference. However, Staff notes that the Commission has previously rejected the use of historical data in determining a company's cost of common equity. Staff Init. Br. at 68-71. As for Staff's claim that Mr. Moul did not provide quantitative support for adjusting the S&P Public Utilities equity risk premium downward to reflect the lower risk of the utility sample, the Utilities say Mr. Moul used informed judgment based on differences in risk fundamentals. Id. at 82.

Regarding City-CUB's assertion that Mr. Moul selectively chose the historical time periods to use, the Utilities counter that Mr. Moul selected fixed periods that cannot be manipulated as later financial data becomes available, and has used these same periods consistently in his work. They add that he gave greater emphasis to more recent data periods so that his equity risk premium would most reflect the market fundamentals most likely to exist for the future. Id. at 82-83.

2. Staff's Position

Staff estimates PGL's investor-required rate of return on common equity to be 9.70%. Staff applied the DCF and CAPM to the sample of gas utilities that Mr. Moul used in his estimate of return on common equity. Staff witness Kight-Garlisch believes that Mr. Moul's sample utilities are reasonable operating risk proxies for Peoples Gas and North Shore.

Ms. Kight-Garlisch's recommended cost of common equity for North Shore is 9.50%, using essentially the same analysis and arguments she used for Peoples Gas. However, Staff's revenue requirement recommendations, including its cost of common equity recommendation, indicate a level of financial strength commensurate with an AA credit rating for North Shore. Thus, the differences in financial strength between the two Utilities produced different cost of common equity recommendations.

For North Shore, Ms. Kight-Garlisch adjusted the results of her utility sample cost of equity estimate, 9.79%, downward by 29 basis points (the spread between A rated and AA rated 30-year utility debt yields). Thus, Ms. Kight-Garlisch's recommended cost of common equity for North Shore is 9.50%.

Staff emphasizes that the difference between the results of Mr. Moul's CAPM and DCF analyses (excluding his adjustments) and Staff's analyses is only 11 basis points. Staff claims that the major differences between the Utilities' and Staff's cost of common equity recommendations result from Mr. Moul's adjustments to the utility sample's cost of common equity. Mr. Moul adjusted his results because the market-value based common equity ratios of his sample are higher than the book-value based equity ratios for the Utilities. He also made an adjustment for flotation costs. Ms. Kight-Garlisch adjusted her utility sample cost of common equity to reflect her view of the lower financial risk of the Utilities compared to the utility sample.

Staff also criticizes the Utilities' use of historical data, arguing that historical data favors outdated information that the market no longer considers relevant over the most recently available information. Second, Staff argues that historical conditions may not continue in the future. (Staff Init. Br. at 68.)

a) DCF

Ms. Kight-Garlisch utilized a constant-growth quarterly DCF model. She measured the market-consensus expected growth rates with projections published by Zacks, Yahoo, and Reuters. The growth rate estimates were combined with the closing stock prices and dividend data as of April 25, 2007. Based on this growth, stock price,

and dividend data, Ms. Kight-Garlisch's DCF estimate of the cost of common equity is 8.23% for the utility sample. Staff Init. Br. at 53.

Staff rejects City-CUB's opinion that the annual version of the DCF model is superior to the quarterly version. Staff notes that dividends are paid quarterly, not at year's end, putting money in investors' hands sooner. Moreover, in addition to its theoretical preference for the quarterly DCF model, Staff emphasizes that the Commission has explicitly rejected the annual DCF model in previous proceedings.

Staff also contests the Utilities' assertion that Staff's application of the DCF model is flawed because the results for some utilities in the utility sample are too low. Staff says its recommendation is based upon a representative sample, rather than any individual company's estimate, because estimates for a whole sample are subject to less measurement error. In Staff's view, eliminating utilities on the basis of their individual DCF results without regard to the effects of such action on the overall sample is improper, because it would defeat the purpose of using a sample. Staff states that removing the two utilities Mr. Moul complains about would reduce the sample to six, and, all else equal, a larger sample better mitigates the potential measurement error of the individual company cost of common equity estimates[17]. In addition, Staff asserts that Mr. Moul singled out utilities in the sample with "low" results. Staff Rep. Br. at 28-29.

b) CAPM

Staff states that the CAPM requires the estimation of three parameters: beta, the risk-free rate, and the required rate of return on the market.

For the beta parameter, Ms. Kight-Garlisch combined betas from Value Line and a regression analysis she performed. The average Value Line beta estimate was 0.87, while the regression beta estimate was 0.62. Staff Init. Br. at 53-54. Staff argues that the validity of its beta estimation methodology is not, as the Utilities suggest, a function of whether investors rely upon Staff's estimates, but whether the methodology is generally accepted. Staff claims it has regularly used its methodology and the Commission has consistently approved it. Moreover, it employs the same monthly frequency of stock price data as the widely accepted Merrill Lynch methodology.

According to Staff, Value Line and regression betas are estimates of the unobservable true beta, which measures investors' expectations of the quantity of non-diversifiable risk inherent in a security. Staff contends that the relative accuracy of the estimates is unknown. Staff also avers that other sources publish beta estimates for the utilities in the utility sample that are even lower than the regression beta estimates. Staff Rep. Br. at 26-28.

For the risk-free rate parameter, Ms. Kight-Garlisch considered the 4.83% yield on four-week U.S. Treasury bills and thirty-year U.S. Treasury bonds, each measured

[17] Staff states that if the Commission deems it appropriate to remove Nicor and Atmos Energy from the DCF analysis as outliers, the CAPM analysis would reduce its estimate of the cost of common equity from 11.34% to 10.91%. Staff Rep. Br. at 29-30.

as of April 25, 2007. Since the yields on the two Treasury securities were identical, her estimate of the risk-free rate is 4.83%.

For the expected rate of return on the market, Ms. Kight-Garlisch conducted a DCF analysis on the firms composing the S&P 500 Index. That analysis estimated that the expected rate of return on the market was 13.46% for the first quarter of 2007. Inputting those three parameters into the CAPM, Ms. Kight-Garlisch calculated a cost of common equity estimate of 11.34% for the utility sample. Staff Init. Br. at 53-54.

Staff states that City-CUB fails to prove that DCF is a superior model to CAPM. Staff believes the use of multiple models improves the cost of common equity estimate. In Staff's view, Mr. Thomas erroneously attempted to correct the Utilities' CAPM analysis by using raw beta and the equity market risk premium from financial literature, instead of calculating a current equity market risk premium. According to Staff, empirical tests show that securities with raw betas lower than one tend to realize higher returns than the CAPM predicts, while securities with raw betas greater than one tend to realize lower returns than the CAPM predicts. Adjusting the raw beta estimate towards the market mean of 1.0, Staff asserts, results in a linear relationship between the beta estimate and realized return that more closely conforms to the CAPM prediction. Thus, Staff believes that Mr. Thomas' criticisms do not justify dismissal of CAPM as a useful model. Staff Init. Br. at 66-67.

c) Adjusted Results

Based on her DCF and risk premium analyses, Staff witness Kight-Garlisch estimated that the cost of common equity for the utility sample is 9.79%. To determine the suitability of that cost of equity estimate for North Shore and Peoples Gas, she compared the risk level of the utility sample to Peoples Gas and North Shore. Id. at 54. She concluded that Peoples Gas' financial strength is greater than the utility sample's A average credit rating, which indicates that Peoples Gas has less financial risk and thus less total risk than the sample. Since investors require lower returns to accept lower exposure to risk, she adjusted the 9.79% utility sample's investor-required rate of return downward to 9.70% (for the 9 basis point spread between A rated and AA- rated 30-year utility debt yields). Id. at 56.

Staff adds that it is appropriate to adjust the cost of common equity for Peoples Gas to reflect a credit rating of AA-, not only because the benchmark financial ratios that result from Staff's proposed revenue requirements are those of a company with an AA- credit rating, but also because Peoples Gas' affiliation with unregulated or non-utility entities lowered its credit ratings. On September 26, 2002, Standard and Poor's downgraded Peoples Gas to A- from AA-. Staff says the downgrade resulted from Peoples Gas' parent company's "increasing business risk with the growing share of nonregulated business." Id. at 56-57.

As previously discussed, Section 9-230 of the Act prohibits the Commission from including in rates the incremental risk or increased cost of capital resulting from a utility's affiliation with unregulated or non-utility entities. Staff argues that since Peoples Gas' A- credit rating is a function of its affiliation with unregulated or non-utility entities, the cost associated with that credit rating cannot be reflected in Peoples Gas' rates.

Staff claims that its downward adjustment to the cost of common equity of the utility sample addresses the requirements of Section 9-230. Id. at 57-58.

3. City-CUB's Position

City-CUB state that its witness, Mr. Thomas, principally based his estimate of the Utilities' required return on common equity Utilities on the results of a DCF analysis. That analysis estimates the return on equity the market demands for investment in a firm with the Utilities' level of riskiness – without what the City-CUB describe as the add-on adjustments that Mr. Moul used. Mr. Thomas used the CAPM to validate his DCF result. City-CUB Init. Br. at 27.

a) DCF

Mr. Thomas used an annual version of the DCF, asserting that the quarterly version overestimates the required rate of return. City-CUB state that other regulatory bodies have embraced the annual version. Id. at 29-30. City-CUB reject Staff's quarterly dividend adjustment because it focuses on working capital. Dividends are paid from retained earnings, not working capital. The authorized return on equity compensates investors for the risk of their utility investment. Id. at 27-28.

Purporting to minimize inconsequential disputes and to highlight the effects of the Utilities' adjustments, Mr. Thomas used much of the same data that Mr. Moul selected for his DCF analysis. He used the same proxy group of comparable utilities, as well as data sources and time periods from Mr. Moul's workpapers. He did not use Mr. Moul's sustainable growth rate, the quarterly adjustment to the expected annual dividend yield, or Mr. Moul's flotation and leverage adjustments. Mr. Thomas believes these elements are unreasonable and sources of upward bias. Id. at 27-28.

For his growth rates, Mr. Thomas used the internal growth rate that he claims recognizes the expected decline in dividend payout ratios, and the resulting disparate dividend and stock appreciation growth rates, for utilities in Mr. Moul's proxy group. City-CUB argue that using the internal growth rate obviates any need for consideration of Mr. Moul's proposed leverage adjustment, which they claim protects the Utilities' high market-to-book ratio.

City-CUB maintain that analysts' forecasts overestimate growth in dividends. Id. at 28-29. They describe the Utilities' counter-arguments as, first, utilities could be different, and, second, the accuracy of forecasts is irrelevant. City-CUB states there is no evidence that utilities are different. As for the second argument, City-CUB stress that the Utilities endorse Mr. Moul's subjective analyses because his aim is merely to identify "expectations," rather than market-required returns (reflected in the achieved returns that actually induced capital investments). Id. at 30-31.

City-CUB assert that Mr. Moul's growth rate input to his DCF model produces significant bias. They say he takes projected earnings per share growth rates taken from "optimistic analysts." Further, rather than simply using the average of those analyst growth rates, Mr. Moul made an upward adjustment, ostensibly to give consideration to the long-term projected growth rate in corporate profits. City-CUB

argue that the projected growth in overall corporate profits generally outpaces regulated utility earnings. Id. at 41.

City-CUB also object to Mr. Moul's upward leverage adjustment to compensate for application of authorized rate of return to the book value of rate base, rather than to the market value of rate base assets. They argue that this adjustment rewards investors with extra compensation because the Utilities' market-to-book ratio is above 1.0. City-CUB states that Mr. Moul would achieve the higher return he advocates by applying an upwardly adjusted return on equity to the book value of the Utilities' shares, an adjustment equivalent to applying the unadjusted return on equity to the market value of all shares - an adjustment the Commission rejected in Docket No. 06-0070. They maintain that applying the Commission-determined return to the market, instead of to the book value of the capital devoted to providing utility service, would allow the Utilities to earn unlawfully on more than their authorized rate base. According to the City-CUB, the entire difference between Mr. Thomas' DCF estimate of 8.11% and Mr. Moul's 9.72% estimate is attributable to the effects of Mr. Moul's inappropriate growth and dividend yield inputs and his unlawful flotation and leverage adjustments. Id. at 41-42.

b) CAPM

City-CUB contend that the result of Mr. Thomas's DCF analysis (8.11%) was validated by the closely aligned result of his CAPM analysis (8.18%). Mr. Thomas used unadjusted betas in his CAPM analysis, rejecting beta adjustments to correct for a presumed reversion of the beta variable to a value of 1.0. City-CUB state that the distinctive nature of utility stocks undermines that presumption. They say that utilities with betas below 1.0 would have to make themselves more risky to validate the presumption. City-CUB note that the Utilities' proposals in this case demonstrate that they actually seek to minimize risk. City-CUB Init. Br. at 30-31.

City-CUB are not proponents of the CAPM, which Mr. Thomas employs only as a validator of his DCF analysis. City-CUB prefer the DCF model that relies more on objective market factors and less on subjective determinations of investors or the analyst. They claim that subjectivity, along with the serious theoretical and practical problems inherent in the CAPM, makes the DCF estimates more useful to the Commission. City-CUB Rep. Br. at 24.

A particularly relevant deficiency of the CAPM, City-CUB argue, is the deliberate exclusion of non-systematic risk factors from its return on equity estimation. They say that a fundamental premise of the CAPM methodology is that non-systematic risks peculiar to a specific utility, like the revenue assurance riders requested here, have no effect on its required return on equity. With regard to the revenue assurance riders, City-CUB claims that every witness actually rejects the premise that risks peculiar to a utility do not affect its required return on equity because it can be diversified away. City-CUB Rep. Br. at 24.

City-CUB opine that three main factors differentiate Mr. Thomas' and Ms. Kight-Garlisch's CAPM analyses. First, Ms. Kight-Garlisch, unlike Mr. Thomas, adjusted the beta estimate for the Utilities to effect a purported regression to the market beta of 1.0.

While Staff believes that this adjustment produces a result that is closer to the CAPM prediction, City-CUB say that Staff's argument simply assumes that the CAPM prediction is the appropriate return on equity estimate. Mr. Thomas says that the CAPM prediction is flawed and does not warrant equal weight with the DCF estimates, short of any biased modifications. Id. at 27.

Second, City-CUB and Staff selected different yield dates for the government securities that represent the risk-free return rate. Third, Ms. Kight-Garlisch computed her own expected market risk premium (the increment of return investors require for investing in the market as a whole). Mr. Thomas relied instead on the available body of empirical research on this issue, on the rationale that the expected general market risk premium is not unique to Illinois utilities or to this state. City-CUB claim that Staff's calculation of the expected market risk premium is approximately 72% above the premium established by the research literature and is 31% above the premium assumed by Mr. Moul. Id. at 34-35.

Staff acknowledges the differences between its and City-CUB's CAPM analysis, but maintains that its use of an adjusted beta and a current calculated market risk premium is consistent with the methodologies accepted by the Commission in numerous proceedings. Staff Rep. Br. at 31 (citing Dockets 06-0070/06-0071/06-0072 Cons., Order at 122, 143-145; Dockets 05-0071/05-0072, Order at 52-53; Docket 03-0403, Order at 32-33 and 42).

c) Risk Premium Model

City-CUB say that Mr. Moul performed a risk premium model estimate that is theoretically similar to the CAPM. They complain that Mr. Moul relies on only 75 years of data and selectively chooses time periods within that 75 years that produce an upward bias due to the strength of the US bond market during the 1980's. They say the Commission has rejected similar risk premium analyses in the past, and Mr. Moul has not justified a reversal of the Commission's position now. City-CUB Init. Br. at 44.

City-CUB note that Mr. Moul presented a comparable earnings estimate, 14.30%, as a check on his other estimates. They argue that the risk characteristics of utilities and unregulated firms are too dissimilar and that the extraordinary result of Mr. Moul's comparable earnings analysis should disqualify it from serious consideration. Id. at 44.

d) Criticisms of Other Analyses

City-CUB emphasize that Mr. Thomas' recommendation was based on DCF and CAPM results that were only marginally different and can viewed as mutually validating analyses. They claim Mr. Moul's biased adjustments push his recommendation far above the level of reasonableness. For this reason, the City-CUB suggest that the Commission's deliberations focus on the City-CUB and Staff recommendations. Specifically, they suggest focusing on the CAPM implementation issues that principally differentiate the recommendations of Staff and the City-CUB. Id. at 40.

City-CUB complain that Mr. Moul's final test of return on equity uses other commissions' return on equity determinations for utilities not shown to share relevant characteristics with the Utilities. They say he relies on this despite admitting that such

subjective expectations might differ from the market-required return on equity. City-CUB assert that tracking commission orders does not lead to the actual market requirement. They say that that Mr. Moul wants investor expectations to mean subjective predictions instead of market requirements. Id. at 35-38.

City-CUB further assert that Mr. Moul and Ms. Kight-Garlisch averaged dissimilar return on equity estimates to produce their recommended returns on equity. They say that Staff's DCF and CAPM estimates differ by over 300 basis points while Mr. Moul's various estimates diverge by over 230 basis points. City-CUB states that different estimates cannot each be a correct measure of objective market factors. They assert that averaging them simply incorporates the errors in each measure into the recommended returns on common equity. Id. at 39-40.

4. All Parties - Market to Book Value

The Utilities adjust their market-based DCF and CAPM models for application to book value, by multiplying the result of a financial model by the utility's market-to-book-ratio. The Utilities state that the costs of equity produced by the financial models are based on the market value capitalizations of the utility sample. The sample's market value capitalizations contain more equity and less financial risk than its book value capitalizations used for ratemaking purposes. The Utilities argue that applying a market-based cost of equity to a book value capital structure yields a mismatch in the financial risks reflected in the two. If a return on equity based on a lower amount of financial risk is applied to a utility's book value capital structure, the utility's earnings will by definition be insufficient to allow the utility to achieve the authorized return.

Staff contends such adjustments are based on the incorrect notion that utilities should be awarded rates of return on common equity in excess of investor-required return whenever their market values of common equity exceed book values. Staff Init. Br. at 61. Staff says there are two possible explanations for how utility stock prices have come to exceed their respective book values: 1) the investor-required rate of return has fallen; or 2) expectations of future earnings have risen. Either way, Staff contends, if a utility's stock price grows to exceed its book value due to a decline in investors' required rate of return for that utility, a lower rate of return should follow. Id. at 62.

According to Staff, it is unwise to allow a utility to earn a rate of return on rate base equal to the product of its market-to-book ratio and the market required rate of return on common equity. That would produce an unending upward spiral as each successive increase in market value would lead to another increase in the allowed rate of return, which in turn, would lead to a further increase in market value. Staff Init. Br. at 64-65.

The Utilities contend that a market price above book value is necessary to maintain the financial integrity of shares previously issued and to avoid dilution when new shares are offered. City-CUB say there is no dispute that the Utilities currently enjoy market-to-book ratios far above 1.0, and assert that the premium reflected in that market-to-book ratio provides access to additional capital without diluting existing shares. City-CUB Init. Br. at 50.

While acknowledging the multiple theoretical reasons for a market-to-book ratio above 1.0, City-CUB underscore the one reason evident here - the Utilities' earnings in excess of their authorized return levels for several years since their previous rate case. In contrast, City-CUB argue, there is no evidence that incentive return awards from this Commission, rewards for excellent management, or market inefficiencies have affected the Utilities' market-to-book ratio. Accordingly, City-CUB maintain that Mr. Moul's leverage adjustment to perpetuate that ratio is unsupportable. City-CUB Rep. Br. at 29.

Nonetheless, Staff also asserts that Mr. Thomas' market-to-book-value analysis is based on the over-simplified premise that a utility should precisely earn its cost of capital on a continuing basis. Staff insists that many ratemaking practices (*e.g.*, deferred taxes and depreciation) can result in a utility's market value exceeding its book value. Thus, Staff avers that a market-to-book-ratio in excess of one does not necessarily mean the authorized rate of return is too high. Staff Init. Br. at 72-73.

5. Staff's Downward Risk Adjustment

Staff's DCF and CAPM market models produced costs of equity of 8.23% and 11.34%, respectively. The average of these two results, 9.79%, was adjusted for "financial risk." The downward adjustments in this case (29 basis points for North Shore and 9 basis points adjustment for PGL), purportedly reflect the lower financial risk of the Utilities relative to the utility sample. The adjustment involves a comparison of the Utilities' stand-alone S&P credit rating to the S&P credit ratings of the utilities in the sample. The Utilities object to Staff's financial risk adjustment. The Commission has accepted such adjustments in prior cases.

Staff emphasizes that the Utilities' current S&P credit ratings are affected by their non-regulated affiliations and are, therefore, not reflective of their stand-alone risk. Staff asserts that since the Utilities' implied forward-looking credit ratings are higher than the average A S&P credit rating of the utility sample, a downward adjustment is necessary. Staff argues, in essence, that because the bond ratings of the Utilities are affected by their non-regulated affiliations, the Commission must look beyond the actual bond ratings to the riskiness of the underlying regulated entities. Staff maintains that it performed a comprehensive analysis and the financial risk of the Utilities is less than that of the utility sample. Staff Rep. Br. at 22-23.

The Utilities say there is no evidence that Staff reviewed and confirmed the similarity of the Utilities to the proxy group on many of the parameters Mr. Moul used to select and confirm his sample. By singling out credit rating and ignoring the other comparability parameters Mr. Moul considered, Staff can misleadingly claim that the risks of the proxy group do not "average out" and therefore fail to provide a reasonable basis for the Utilities' market models. However, the Utilities assert, while the utility sample reflected a different average credit rating than the Utilities, that difference was offset by differences in other financial parameters that indicate the Utilities have more risk than the proxy group. NS-PGL Rep. Br. at 57.

Moreover, the Utilities suggest, if Mr. Moul's proxy group was not sufficiently comparable with respect to credit rating, it may not have been comparable with respect to other factors - or, differences in other factors could have offset the lack of

comparability on credit rating. NS-PGL Init. Br. at 83-85. The Utilities argue that if Staff did not believe Mr. Moul's proxy group reflected comparable risk (operational and/or financial), Staff should have assembled a different proxy group that it believed "balanced" both operational and financial risk as compared to the Utilities.

The Utilities charge that Staff's financial risk adjustment is inconsistent with its position on Mr. Moul's financial leverage adjustment. In each case, the Utilities assert, the witness adjusted the Utilities' rates of return to reflect their capital structures, in particular their debt leverage. Thus, Staff cannot have it both ways, ignoring the differences in capital structures reflected by its market model results and the Utilities' book value capital structures, while adjusting another market models' results to reflect the Utilities' debt leverage as represented by their credit ratings. Id. at 85-86.

Staff responds that Mr. Moul's opposition to the use of credit ratings in evaluating the reasonableness of a cost of equity estimate is inconsistent with his own use of credit ratings and leverage ratios to evaluate a sample used to estimate cost of common equity. Further, Staff argues, the Commission should not ignore the financial strength implied by the benchmark ratios in comparing the risk of Peoples Gas and North Shore versus the proxy sample. Staff maintains that since the implied forward-looking credit rating is higher than the average A credit rating of Ms. Kight-Garlisch's sample, a downward adjustment is necessary to reflect the basic tenet of financial theory that the investor-required rate of return is lower for investments with less exposure to risk. Staff Init. Br. at 60-61.

The Utilities also complain that Staff's financial risk adjustment contains an unexplained differential in the treatment of North Shore and Peoples Gas, despite the fact that the two utilities have had the same credit ratings for at least the past five years. According to the Utilities, if there should be any disparate treatment between the two, there should be an upward adjustment of North Shore's return on equity to reflect its small, stand-alone size. Id. at 86.

Staff opposes increasing North Shore's cost of common equity to reflect it smaller size. Staff avers that if a size-based risk premium exists for utilities, it should be based on the size of the Utilities' parent company, Integrys. Although North Shore raises its own debt, it obtains common equity financing from its parent company. Staff observes that Integrys has a market capitalization of over $3.87 billion and being a part of a much larger organization should enhance the ability of North Shore to access the common equity market on reasonable terms. The Commission, Staff points out, has rejected a size-based risk premium in many cases, including Docket No. 03-0403. Staff Rep. Br. at 23-24.

6. Returns Approved for Other Utilities

The Utilities argue that the Commission should consider other rates of return recently allowed for other gas utilities in Illinois and elsewhere. The Utilities cite fifty-four cost of common equity decisions for electric and gas utilities for 2006 and contend that they demonstrate the insufficiency of Staff's and City-CUB's recommendations. The Utilities state that rates of return on equity awarded to gas utilities in the United States averaged in the mid-10% range in 2006, and 10.35% through March 2007. They

add that Value Line forecasts the natural gas utility industry to earn 11.5% in 2007 and 2008. Also, in Nicor Gas' last rate case, the Commission approved a 10.51% return. NS-PGL Init. Br. at 91. The Utilities note that City-CUB's recommended returns on equity are far below any return authorized by this Commission for a gas utility in the last thirty years, and so far below any return awarded to a gas utility by any state commission in recent years, that they do not merit serious consideration. NS-PGL Rep. Br. at 52.

Staff replies that Mr. Moul failed to address critical factors that influenced the allowed returns in the fifty-four proceedings. Staff says Mr. Moul did not identify the relative risk, as exemplified by credit rating or any other metric, of each of the pertinent utilities. Nor did he identify the capital structure or the amount of common stock flotation cost adjustment, if any, included in those decisions. Without such data, Staff argues that any comparison of return recommendations is useless. Staff Rep. Br. at 30.

Moreover, Staff contends, given the financial strength implied by the Utilities' forecasted financial ratios, it would expect the Utilities' required return on common equity to be considerably lower than average. Staff notes that its recommendations of 9.5% for North Shore and 9.7% for PGL are below the 10.49% average allowed by U.S. regulatory commissions in 2006, while the Utilities' return request of 11.06% is above that average. In any event, Staff says, the Commission has rejected this type of comparability in ComEd's most recent delivery services docket. Id. at 30-31.

7. Effect of the Utilities' Proposed Riders

Staff and City-CUB argue that if the Commission approves proposed Riders VBA and UBA, the Utilities' authorized rates of returns should be reduced to reflect the resulting reduced risk. In particular, Staff asserts the riders would reduce operating risk, which the Utilities acknowledge is part of investment risk. Staff reasons that since investor-required rate of return is lower for investments with less risk exposure, the riders should reduce rate of return. Staff avers that because the riders would transfer risk from the Utilities to ratepayers, none should be approved without compensation through lower authorized rates of return. Staff Rep. Br. at 26.

City-CUB attempt to quantify the financial risk impact of the riders by comparing them to the value of weather insurance policies the Utilities' corporate parent previously purchased to protect shareholders against earnings shortfalls in the event of significantly warmer weather than forecasted. Mr. Thomas valued the insurance protection by noting, first, that Peoples Gas shareholders were willing to pay a significant premium for the lower level of revenue assurance (as compared to the proposed riders) the weather insurance policy provided, and, second, that the payout would have provided a benefit equal to an after-tax return on equity benefit of 0.695% to Peoples Gas and 0.660% to North Shore. City-CUB Init. Br. at 46-47.

According to the City-CUB, because the protection provided by the policy was significantly less favorable to Peoples Gas than the riders would be, Mr. Thomas' derived estimate of the return on equity effect is very conservative. They say they confirmed this with a "backcast" of the effect of Rider VBA alone, had it been in effect for the single year 2005. They contend that the $4.47 million net benefit from the

maximum policy payout pales in comparison to the $30 million that PGL could have realized from only one of the proposed riders. Id. at 47.

The Utilities criticize Mr. Thomas' analysis, which takes the maximum payout under one of the policies, deducts the premium paid, and treats the net payout as the value of the policy. They argue that the value of an insurance policy must reflect the probability of the payout. They say the value of the policy is therefore represented by the premium amount, which should equal the average expected payout less administrative costs.

In addition, the Utilities assert that Mr. Thomas did not consider that the weather insurance policy required Peoples Gas Energy Corporation to pay an additional premium if weather was somewhat colder than forecasted (akin to Rider VBA requiring refunds). They say that under Rider VBA there is "payout" to the Utilities if weather is warmer than forecasted, but the "payout" is to ratepayers if weather is colder. NS-PGL Init. Br. at 89-90.

More generally, the Utilities reply that there is no evidence that approval of the riders would have any impact on investor-required return, theoretical or otherwise. They say Staff and City-CUB simply presume an impact and suggest methodologies to calculate the reduction. NS-PGL Init. Br. at 86-87. The Utilities state that under the financial theory upon which the cost of common equity is based, investments are valued on a long-term basis. They say the DCF model expressly assumes a growth rate that approaches infinity, and the CAPM expressly ignores company-specific, unsystematic, risks. They insist that the investor-required cost of capital for a gas utility is not affected by variations in usage due to weather and therefore is the same either with or without a VBA rider. Id. at 87.

Additionally, the Utilities claim, such riders do not affect the investor's required return because weather and uncollectibles are not business risks that investors take into account. However, even assuming that the riders would affect the cost of equity, the Utilities say no evidence supports Staff's assumption that approval of the proposed riders would cause S&P to increase the Utilities' business profile score a full notch to 2. Id. at 89.

The Utilities further assert that the riders would protect shareholders and ratepayers alike from the risk of variations from the "normal" assumptions for weather and uncollectibles used for ratemaking purposes. The Utilities also claim that the majority of Utilities in the utility sample used by all three cost of capital witnesses have similar cost recovery mechanisms and their financial data reflect that fact. They thus emphasize that the Missouri Public Service Commission recently refused to adjust a gas utility's authorized rate of return for precisely this reason. Id. at 88.

Indeed, the Utilities propose that rates should be *increased* if the riders are rejected, based on the financial parameters of the utility sample. Staff responds that the Utilities have no riders now, yet have the same level of operating risk as the Gas Sample, which includes Utilities that have some of the tracking mechanisms the Utilities have requested in this proceeding. In Staff's view, approving some or all the riders would reduce the Utilities' operating risk below that of the utility sample, which would

further lower the Utilities' cost of common equity. City-CUB assert that the scope and economic effect of the other utilities' tracker mechanisms have not been compared to the Utilities' proposed riders. They say at least one of the proxy utilities has no mechanism like the riders here, while another has what can more accurately be called a conditional rate design element than a revenue assurance rider.

City-CUB charge that the Utilities make a new argument in their Initial Brief that the riders are "risk neutral" because they "protect shareholders and customers alike." They assert that the additional revenues identified by the Utilities' "backcast" analysis, a $30 million increase in customer charges, demonstrate that the riders are not risk-neutral from customers' perspective. They claim that the fact that the Utilities have proposed the riders belies any pretense that they are risk-neutral - there would be no point in proposing a rider that would have a "neutral" effect on today's risk allocation. City-CUB Rep. Br. at 26.

8. Commission Conclusions

The Commission has established rates of returns on common equity for utilities by employing financial models designed to quantify the likely cost of attracting capital investment during the time rates are expected to be in effect. In virtually all cases, we have relied on the DCF and CAPM models. In these proceedings, Staff employed the DCF and the CAPM. City-CUB relied primarily on the DCF model and used the CAPM to verify the results. The Utilities used DCF, CAPM and risk premium models, as well as a comparison with ROEs granted to other utilities in and out of Illinois.

As a result, the disputed ROE issues principally concern differences about proper application of the DCF and CAPM models, the inter-relationship of the models, adjustments to results, and the efficacy of the additional models used by the Utilities. While most of these issues involve the mechanics of financial modeling, the Utilities' comparison of the ROEs proposed here with ROEs authorized for other utilities poses broader and more conceptual questions that the Commission will address first.

ROE Comparisons

At several places in their evidence and briefs, the Utilities compare the ROE's recommended here with the ROEs approved in previous cases by this and other commissions. E.g., NS-PGL Ex. PRM-2.0 at 3-6. They assert that previously approved ROEs serve as "guideposts" for our analysis in these cases and insist that they "are not arguing that their returns should be based on the authorized returns of other utilities." NS-PGL BOE at 25. The Commission doubts that the Utilities' return comparisons were offered without the expectation that our decision-making would be affected by them. The Utilities are presumably reluctant to directly press for comparison-based ratemaking because of our previous rejection of that approach. In Commonwealth Edison's most recent rate case, we said:

> ComEd asserts its cost of equity should reflect the costs of equity recently approved for electric utilities in the United States. The cost of equity

> appropriate to ComEd, however, is specific to that utility. ComEd may not simply adopt the cost of equity set for other utilities scattered around the country, for which the factors and circumstances are not necessarily similar. Rather, pursuant to Section 9-201 of the Act, ComEd must prove that its proposed cost of equity is just and reasonable.

Commonwealth Edison, Docket. No. 05-0597, Order, at 153 (June 6, 2006).

That does not mean, though, that the Commission is unaware of the implications of the ROE we adopt for the Utilities. They must compete for investors' money and cannot be deprived of meaningful capacity to do so. Nonetheless, there are important reasons why a commission should not simply match each Utilities ROE to the others previously approved. If our task were merely to maximize the Utilities' ability to attract capital (perhaps to retain investment in Illinois, as the Utilities suggest, Tr. 1047-48 (Moul)), the Commission could just exceed the highest returns already authorized for other utilities. But when the next utility initiated a rate case, we would have to approve an even higher return. Moreover, the Utilities point out that "regulated firms must compete with non-regulated firms in the capital market." NS-PGL Ex. PRM-1.0 at 41. To assure success in that competition, the Commission would presumably have to equal or exceed returns in the unregulated market as well.

Less dramatically, we could aim for an average among existing ROEs. However, some percentage of existing ROEs would have been in effect for multiple years and would have been established under different financial market conditions (*e.g*., with different rates of inflation and costs of debt). The Commission could narrow its comparison to, say, ROEs approved within the last two years, and peg the Utilities at the average of those. Even then, we would have to ignore any differences among utilities in financial strength, capital structure, credit status and utility-specific circumstances, as well as changes in the financial market during the two-year period. Moreover, while this one-dimensional comparative approach might satisfy us for ratemaking purposes, it would not necessarily attract capital from sophisticated investors, who would evaluate the actual financial strengths and weaknesses of the utilities. Indeed, an ROE simplistically pegged to average recent ROEs might be too low.

Furthermore, by determining the Utilities' ROEs via comparison to existing ROEs, the Commission would be disregarding its duty to impose only cost-based and reasonable rates on the Utilities' customers. Thus, if we succeeded in providing capital attraction to Illinois utilities, we would also be extracting it from Illinois businesses and homeowners, in the form of excessive rates. And, in the future, other Commissioners could reverse the inequity, by intentionally pegging the Utilities' returns to the lowest comparable existing ROEs.

Plainly, although the notion that the Utilities should enjoy at least an average ROE is superficially seductive, it is an unworkable and improper basis for determining utility returns. It would require us to abandon the course we, along with other

commissions, have charted for decades. Return determinations are appropriately based on a two-pronged analysis of utility-specific financial characteristics and financial market dynamics and conditions. We have relied upon the financial models and reasonable adjustments to accomplish this. Although even these quantitative mechanisms involve some degree of subjectivity[18] and can, for that reason, be manipulated, they were constructed with the intention of objectively estimating the cost of equity, not to match another utility's ROE.

In sum, the Commission will not award the Utilities the same ROE as, for example, Nicor, solely because they must compete for investment capital. If market dynamics have altered since the Nicor decision in 2005, that will be reflected in the Utilities' ROE. So, too, will utility-specific differences. A critical difference is that the Utilities will enjoy the revenue stability and reduced risk derived from Rider VBA, approved in this Order. Nicor Gas has no such rider.

Another critical difference is the Utilities' recent merger, with WPS, which the Utilities assured us would enhance their financial strength. As the Utilities see it, they have proven that the merged entity, Integrys, "will provide the Utilities with a larger and stronger financial platform," and "has a strong record of maintaining the financial strength of its regulated subsidiaries." NS-PGL BOE at 23-24. The Utilities cannot have it both ways, heralding the increased financial strength derived from their 2007 merger, then requesting an even higher allowed ROE than Nicor received in 2005, based upon the rationale of parity (or more) for its own sake. Accordingly, the Utilities' approved ROE in these proceedings will be determined by application of the financial models and adjustments we have continually relied upon since the early 1980's[19].

The DCF Model

Staff's DCF analysis yields (after adjustment) a cost of common equity of 8.23%. The Utilities believe this is far too low (their estimate is 9.72%). They complain that Staff erred by taking a snapshot of certain DCF inputs (stock prices and dividend data) from a single day in April 2007. The Utilities say the data is now too old. The Commission finds it inevitable that data in pre-filed rate case testimony will reflect some degree of hindsight, at least as a starting point in the analysis. That attribute is common to much of what the parties presented as evidence, including the Utilities' own DCF analysis. Furthermore, we are establishing an ROE that will remain in place until the Utilities' next rate case, potentially long after this Order is entered. As the Utilities state,

[18] "The truth is that the application of all of the models involves the analyst's judgment in choosing the various inputs to the models from a plethora of financial data." PGL-NS RBOE at 37. "[N]o estimation methodology is entirely objective." City-CUB Init. Br. at 36.

[19] *E.g.*, Central Illinois Public Service, Docket No. 82-0039; Commonwealth Edison, Docket No. 82-0026; Commonwealth Edison, Docket Nos. 83-0537 & 84-0555; Illinois Power, Docket No. 84-0480.

an ROE is intended to provide an opportunity to earn a fair return over "good years and bad." NS-PGL BOE at 27-28.

Staff is also concerned about the use of historical data in calculating forward-looking ROEs, since all historical data is outdated and may reflect conditions that will not continue in the future. Yet the problems cited by Staff are compounded by short-term "vagaries of the market" (NS-PGL Ex. PRM 2.0 at 7) that can affect stock prices and yields on any given trading day, which Staff proposes as a starting point on its DCF analysis. The use of price and yield averages, as the utilities propose, will tend to smooth out any exogenous short term price and yield inefficiencies that can occur on a single trading day. Thus, Staff's single data point for use in its DCF is unsatisfactory for the intended purpose in these dockets.

The Utilities further charge that Staff's DCF results are too low to be credible, suggesting faulty methodology. Staff replies that the Utilities over-emphasize the lowest-ranking results in Staff's treatment of the nine companies in the utility sample, thereby contradicting the very purpose of assembling a multi-utility sample in order to derive an average. There will always be a high and a low in a sample, Staff says, but the meaningful data point is the average. While Staff is correct on these points, there is another obvious check on Staff's results: the use of an alternative sample date or an average across a six-month, or other, period that the utilities argue would be better. We believe that the anomalous results produced by Staff's DCF analysis render it flawed and therefore unusable to determine ROE in this case.

We note that the Commission has traditionally relied upon a single day's data in applying the DCF analysis, and we are very reluctant to deviate from Commission ratemaking practice. However, the whole point of conducting such analyses is to develop a proxy for the appropriate ROE. When it can be shown that the proxy itself strays from a zone of reasonableness to the degree where it offers an unreliable estimate of the appropriate ROE, as the Utilities have demonstrated with Staff's DCF analysis in this case, deviation from accepted practice may be warranted. We encourage parties to continue to provide reliable DCF analyses for the Commission's ROE deliberations.

Staff and the Utilities used a quarterly version of the model and disagree with the choice of City-CUB to use an annual version. The Commission finds that the quarterly version of the DCF model is superior. We remain convinced, as we have been in numerous previous rate cases, that the quarterly version of the model should be used to correctly reflect the time-sensitive value of the dividends reflected in the DCF model. City-Cub's arguments, which the Commission has considered in previous cases, have not altered our view. Since the City-Cub model does not use quarterly dividend data, it will not be considered in evaluating the utilities' ROE.

The CAPM Model

We do not find City-CUB's arguments against the CAPM sufficiently persuasive to abandon the CAPM. In many prior proceedings, the Commission has regarded the CAPM as a useful tool based upon sound financial theory. As the Utilities and Staff indicate, investors are only rewarded for accepting systematic risk. That is, any risk that an investor can eliminate by holding a fully diversified portfolio of securities need not be reflected in the investor's required return. While City-Cub did not explicitly rely on their CAPM results in developing their recommended return on common equity, they did claim it supported their DCF results.

The Commission rejects City-Cub's suggestion that unadjusted, or raw, betas should be used as inputs to the CAPM. As both the Utilities and Staff point out, the financial literature and empirical studies support the use of adjusted betas as better forward-looking measures of systematic risk. We have regularly relied upon adjusted betas in establishing authorized returns on common equity and the arguments of City-CUB have not convinced us to change this practice.

City-Cub also object to the manner in which the Utilities and Staff developed their expected market risk premium for use in the CAPM. As with the risk premium between utility cost of debt and cost of common equity, the expected market risk premium relative to the risk free rate is not stable over time. As a result, the Commission concludes it is preferable to rely upon a current estimate of the expected market risk premium rather than upon an approach derived from academic research.

Risk Premium Model

The Commission understands that the CAPM is similar to a risk premium model. However, the risk premium model that the Utilities used in addition to their CAPM is unhelpful. The primary reason that the Commission has repeatedly rejected that type of risk premium analysis is the difficulty in establishing the "correct" risk premium. The risk premium for common equity relative to debt changes over time and, in the Commission's view, there is no objective mechanism for establishing that risk premium. While all cost of equity analyses require the application of judgment, this particular approach is primarily a matter of judgment and we are unwilling to rely on such a subjective analysis.

The Utilities acknowledge that this Commission "has in the past rejected the RP model as a valid basis on which to set [ROE]." NS-PGL BOE at 29 (citing CILCO, Docket No. 02-0837, Order (Oct. 17, 2003)). Despite that, the Utilities contend that the risk premium should still be utilized, in conjunction with the Utilities' other models, to determine ROE in the instant dockets. The Utilities assert that the Commission ratified that viewpoint in Commonwealth Edison, Docket No. 05-0597, Order (June 26, 2006), when we relied, in part, on an intervenor witness whose ROE recommendation was derived from three models, including the risk premium. Staff responds that the witness did not give risk premium equal weight with his other models, that the Commission also used Staff's recommendations (without risk premium) to set ROE, and that the issue was not analyzed as it has been here. Staff RBOE at 23-24. The Commission again

rejects the risk premium model. Insofar as it crept into decision-making in Docket No. 05-0597, that was an anomaly we will not repeat.

Staff's Adjustments

Staff made downward adjustments to the cost of common equity results to reflect its view that Peoples Gas and North Shore each have less financial risk than the proxy utility sample. Staff accomplished this by comparing the benchmark financial ratios (*e.g.*, funds from operations/interest coverage) of the Utilities and the sample companies. Staff concluded that the resulting financial characteristics of the Utilities' are consistent with a higher credit rating than the utility sample's collective credit rating. The Utilities urge the Commission to reconsider its past practice of accepting such adjustments. The Utilities argue, in essence, that their own proxy utility sample is similar in total risk (operational and financial) to both Peoples Gas and North Shore. They assert that because their sample was selected on the basis of total risk, not just operational risk, a financial risk adjustment is unnecessary and inappropriate. Staff says it accepted that the utility sample had operational risk that was similar to the Utilities', but did not evaluate the similarity of financial risk until after the cost of equity analysis was performed on the sample.

The Utilities did endeavor to consider financial risk in their presentation, including comparing credit ratings. However, the Utilities' credit ratings have been impacted by non-regulated activities. Section 9-230 of the Act requires the Commission to ensure that such activities are not reflected in the authorized rate of return. While the Utilities agreed that an adjustment to the embedded cost of debt was necessary to remove the impact of non-regulated activities, their recommended return on common equity does not appear to reflect such an adjustment.

The Utilities contend that some of the companies in the utility sample are, like the Utilities, also affected by the increased operating risk of their parent companies. They further allege that Staff's witness apparently knew this, because she adjusted the S&P business profile scores of those utilities. But, according to the Utilities, she did not adjust their credit ratings, thereby exaggerating the differential in creditworthiness between the sample companies and the Utilities. NS-PGL BOE at 34. Staff explains, however, that the sample companies' credit ratings did not require adjustment because they already reflected the credit ratings of their parent companies.

On exceptions, the Utilities also argue that even if the Utilities' financial risk is lower than the average of the utility sample, Staff "failed to confirm that there are no risk differences that offset that 'financial risk' difference." NS-PGL BOE at 35. The Utilities assert that there are several pertinent financial risk factors, that the Utilities and the sample companies are, respectively, higher on some and lower on others, and that they "balance out" overall. Staff's shortcoming, according to the Utilities, is the failure to prove that the other factors do not cancel out the impact of the Utilities' ostensibly higher credit rating.

The Commission categorically rejects the Utilities' argument, which turns the burden of proof in these proceedings on its head. Staff is not obliged to disprove all

potential counter-arguments to its recommended adjustments. The burden is on the Utilities to prove the reasonableness of their proposed rates, including the reasonableness of the elements, such as ROE, that make up those rates. In this specific instance, Staff presented sufficient support for its financial risk adjustment to require the Utilities to rebut that support. Staff did not need to disprove any Utilities' rebuttal *that was not made*.

The issue, then, is whether the Utilities offered sufficient evidence and argument to rebut the basis for Staff's adjustments. Their evidence is Mr. Moul's opinion that "on balance" the performance of the nine companies in the utility sample "average out" with the Utilities, with regard to the multiple financial risk factors Mr. Moul applied. No calculations support that opinion. The risk factors are not weighted and compared quantitatively to prove equivalency between the Utilities and the utility sample. Nor is the quantitative impact of those risk factors compared to the quantitative impact of the Utilities' linkage to its parent company's credit standing. Mr. Moul forthrightly acknowledged that quantifying the impact of separate financial fundamentals is generally not possible. Tr. at 1071-72. Therefore, Staff did not need to disprove that the risk factors "balanced out" or that they did not offset Staff's adjustments.

By performing its financial ratio analysis on the regulated entities here, Staff has been able to isolate their financial risk. Staff's analysis thus demonstrates that the Utilities are less financially risky than the utility sample and that downward adjustments to the cost of equity results for that utility sample are necessary. Staff's adjustment is theoretically sound and consistent with similar adjustments accepted by the Commission in previous rate cases.

The Utilities' Adjustments

Staff states that the difference between the Utilities' CAPM and DCF analyses and its own is only 11 basis points, once Mr. Moul's adjustments are removed. Thus, Mr. Moul's financial leverage adjustments require discussion. The Utilities adjust both their DCF and CAPM analyses so that the authorized return applied to the Utilities' book value capital structures will, in their view, correctly represent investor-required return. They maintain that the costs of equity produced by the financial models are based on the market value capitalizations of the utility sample. They further assert that the proxy group's market value capitalizations contain more equity and less financial risk (debt) than its book value capitalizations used for ratemaking purposes, which contain less equity and more financial risk. The Utilities argue that when a market-based cost of equity is applied to a book value capital structure there is a mismatch in financial risks and under-recovery of allowed the utility's allowed return.

In the Commission's judgment, the book value capital structure reflects the amount of capital a utility actually utilizes to finance the acquisition of assets, including those assets used to provide utility service. In establishing the overall or weighted average cost of capital, the proportion of common equity, based on the book value capital structure, is multiplied by market-required return on common equity. The

Commission has used this approach in establishing utility rates for at least twenty-five years. E.g., Ameren Order, Docket Nos. 06-0070/06-0071/06-0072 (consol.) at 141 ("[t]he Commission observes that it has repeatedly rejected arguments in favor of using market-to-book ratios as the basis for establishing cost of common equity"). Market value is not utilized in this calculation because it typically includes appreciated value (as reflected in its stock price) above the Utilities' actual capital investments.

The Utilities assert, however, that theirs is a "financial leverage adjustment," not a "market-to-book adjustment." NS-PGL BOE at 30-31. This elevates form and nomenclature over substance. The Utilities perform their adjustment by first determining the cost of equity for a utility (represented by the average of the utility sample) with a 100% equity capital structure, using the market value of the equity (the result is 8.35%). From that, they then calculate the ROE for a utility (again represented by the average of the utility sample) based on the equity reflected in a book value capital structure (a 9.53% result)[20]. NS-PGL Ex. PRM 1.13, p. 13-14. The Utilities recognize that this process is equivalent to applying an unadjusted equity return to the market value of the utility's shares, resulting in an adjustment identical to the one we rejected in the Ameren Order. City-CUB Cross-Ex. 5. Again, our practice is to approve a return on a utility's actual investments at book value, not on the appreciated value of its common stock, however calculated and denominated.

Further, the Utilities have failed to establish why a mismatch between the financial risk reflected in the book value and market value capital structures is problematic. If the Utilities were correct that regulatory commissions, including this one, have been understating the market-required return on equity for twenty-five years, then the market values of common equity for utilities would not have remained well above the book values during that time. A practice of routinely understating the market-required return on common equity would have surely driven down the market values of common equity to near book value, but that has not happened[21]. Accordingly, the Commission does not agree that an adjustment to the market required return on common equity is necessary to reflect the difference in financial risk between book value and market value capital structures. Therefore, we reject the Utilities' financial leverage adjustment to their DCF results and their proposal to impose a similar leveraging adjustment to the betas used in their CAPM analysis.

Inter-Relationship Among the Models

City-CUB points out the disparity between both the Utilities' and Staff's DCF and CAPM analyses. There is a 232-basis point divergence between the Utilities' adjusted

[20] Stock flotation costs are not included in these calculations.

[21] The Utilities call this conclusion "speculative." NS-PGL BOE at 33. We disagree. It is the accumulated experience of this Commission, and is embedded in the discretion with which we determine ROEs. In these proceedings, it is supported by evidence of the Utilities' own stock appreciation above book value and their earnings, in most years, above their allowed returns.

results[22] and a 311-basis point differential between Staff's. City-CUB questions whether such dramatically disparate results can both be correct (the difference between City-CUB's models is only 7 basis points).

Another seeming anomaly is not in City-CUB's favor. Staff's, the Utilities' and City-CUB's DCF models are less than 100 basis points of each other (8.23%, 8.11% and 9.01% (unadjusted), respectively). But while Staff's CAPM (11.34%) and the Utilities' (10.79% unadjusted, 11.85% adjusted) are relatively close, City-CUB's CAPM result is 8.18%. Viewed in this way, City-CUB's CAPM is the outlier.

The point is not that City-CUB's CAPM modeling is incorrect, but that the proponents of the same model will obtain different outcomes when they make different assumptions about inputs or different adjustment to their results. Similarly, the various models will yield different costs of common equity because they are rooted in different theories of how to estimate those costs. While the Commission might be tempted to disregard the CAPM here, we know, from experience over time, that the CAPM will show less volatility than the DCF model. Our continuing policy is to employ both models and to calculate a mid-point that accords due regard for their different underlying theories.

Effect of the Proposed Riders

In this Order, below, the Commission approves Rider VBA as a 4-year pilot program. That Rider affords the Utilities revenue stabilization when customer usage varies. Staff and City-CUB argue that a downward adjustment to the cost of common equity should be made, because Rider VBA (like the other riders, which are not approved here) would reduce the Utilities' risk. That reduced risk, Staff and City-CUB say, should be reflected in the authorized return on common equity. The Utilities disagree, asserting that some of the utilities in the proxy sample have similar types of riders or comparable revenue stabilization mechanisms. Furthermore, the Utilities argue, the variations addressed by Rider VBA, in particular, are not relevant to investment decisions and are not measured under the CAPM model. Also, the Utilities argue, Rider VBA is "risk neutral" because customers benefit when weather increases gas consumption. NS-PGL Init. Br. at 90.

Initially, the Commission concludes that the Utilities' list of revenue stabilization mechanisms for many of the companies in the utility sample, NS-PGL Ex. 2.4, is insufficient for our purposes here. The Utilities did not compare the operation or quantitative impact of Rider VBA with the proxy companies' listed mechanisms or explain how those mechanisms have (or have not) been reflected in the proxy

[22] The Utilities stress that their *unadjusted* results are "only" 178 basis points apart. PGL-NS RBOE at 37. However, they have insisted throughout these proceedings that their results must be adjusted to be valid, and that other parties' results are invalid without those adjustments.

companies' approved cost of capital[23]. Thus, the record contains no quantitative evidence for comparison and no comparative analysis of the operational characteristics of the various mechanisms and Rider VBA. Given that the cost of equity is measured in (and disputed over) hundredths of a percentage point (i.e., in basis points), this imprecision is significant.

The Utilities' assertion that investors do not take into account the relationship between weather and a gas utility's expected earnings is belied by the Utilities' own testimony. "[T]he market prices of these [Utility Sample] companies' common equity reflect the expectations of investors related to a regulatory mechanism that adjust [sic] revenues for abnormal weather." NS-PGL Ex. PRM-1.0 at 5.

As for the Utilities' claim of "risk neutrality" with Rider VBA, the Commission finds this irrelevant. Rider VBA stabilizes *the Utilities*' revenues. We are not establishing an ROE for ratepayers. Moreover, all the Utilities are really saying is that consumers are not *worse off*, in a limited sense, when weather plummets and usage rises.

Staff contends that Rider VBA (and the other riders) would reduce the Utilities' operational risk, which is part of investment risk. Thus, Staff states, it would assess the reduced risk associated with the relevant rider, evaluate the Utilities' operating ratios based on the reduced risk, and reduce ROE to account for the difference in total risk, as compared to the utility sample. Staff Ex. 6.0 at 22-23. Staff suggests that the Utilities' riders might well reduce operating risk to a point where their S&P business profile were improved. Such improvement "would result in financial ratios that are consistent with stronger credit ratings than Staff's cost of equity recommendations reflect." Id. at 26. The Utilities' own view is consistent with the foregoing analysis:

> Therefore, the [Utilities] can be expected to realize a short-term benefit of improved liquidity as a result of implementation of these Riders. Indeed, the Riders will remove some of the [Utilities'] cash flow variability, which would be viewed favorably by the credit rating agencies. As such, the Riders would help the [Utilities] to sustain [their] credit ratings. These are beneficial impacts which will be most directly manifested at the credit quality level rather than the determination of the [Utilities'] cost of equity.

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[23] Presumably, the Utilities expected the Commission to perform the detailed comparisons. We attempted that task, through our ALJs, and we note, for example, that Piedmont Natural Gas Company's "Rate Stabilization Mechanism" commits the utility to specified ROE limits. Piedmont's rates are adjusted only twice annually, as true-ups. South Jersey Industries' "Temperature Adjustment Clause," which terminated in 2006, had only annual true-ups, not monthly adjustments like Rider VBA. New Jersey Resources' "Weather Adjustment Clause" appears to merely revise HDDs annually. We have identified these provisions, which emphasize apparent differences from Rider VBA, to illustrate the limited usefulness of the Utilities' presentation. If the Utilities' wanted certain inferences drawn from its list, it was up to them to make the detailed comparisons that would have supported those inferences. As the record stands, the list, by itself, does not persuade us that the companies in the utility sample have mechanisms that stabilize revenue and reduce risk in a manner comparable to Rider VBA.

NS-PGL Ex. PRM-1.0 at 7. (Insofar as the Utilities' divorce credit quality from the ROE determination, the Commission simply disagrees. That is why we approved Staff's cost of equity adjustments, which reflect the affect of credit standing and financial ratios.)

City-CUB, as discussed above, attempt to estimate the impact of the riders on cost of equity by reference to the insurance policy the Utilities' parent corporation formerly purchased to hedge against mild weather. In City-CUB's view, the policy proceeds represent an extremely conservative quantification of the impact of the riders on ROE (treating the amount of the policy payout as a proxy for additional revenue). The Utilities assert that City-CUB's methodology is incomplete because it omits necessary elements.

The Commission finds that Rider VBA will lessen the Utilities' risk associated with their cash flow. Moreover, we agree with Staff's recommendation that there should be a downward adjustment to the cost of common equity to account for the reduced risk associated with the accepted riders. Staff Ex. 10.0 at 23. Staff provides guiding principles for quantifying that diminished risk but does not quantify it. City-CUB recommend a sixty (60) basis point reduction if both Rider VBA and UBA are accepted, however we find compelling the Utilities' criticism to the City-CUB analytic approach of using the insurance model. NS-PGL Init. Br. at 89-90. While the record in this case lacks an exact calculation of the reduction in risk due to Rider VBA, we note that determining the cost of common equity is not an exact science. Amax Zinc Co. v. Illinois Commerce Comm., 124 Ill. App. 3d 4, 11-12 (5th Dist 1984). Overall, we find the record to support a downward adjustment, and in the absence of an exact calculation we find it reasonable to reduce the return on common equity by ten (10) basis points for the duration of the pilot program.

As noted later in this Order, the Commission accepts Rider VBA as a 4-year pilot program. To aid us in monitoring this pilot and its impact on the Utilities' rates of return, we direct Staff to provide the Commission with an annual report on Rider VBA's effect on those returns. If Rider VBA is to become permanent, we expect the parties to quantify thoroughly the effect of Rider VBA on ROE in future cases.

Approved ROE

Based on the foregoing discussion, the calculation of ROE will be affected by the following conclusions: (1) the DCF analyses performed by Staff and City-Cub will not be used in the calculation; (2) the Utilities' risk premium model will not be used in the calculation; (3) the Utilities' financial leverage adjustment is rejected; (4) Staff's recommended adjustment to remove the effect of the Utilities' affiliation with unregulated entities is accepted; (5) Rider VBA reduces the Utilities' risk, which warrants a reduction in ROE by ten (10) basis points; and (6) evidence regarding the allowed ROEs in other cases cannot inform as to the appropriate ROE in the present case.

Based upon its review of the record, and consistent with the conclusions above, the Commission finds that an average of the Utilities' unadjusted DCF model, the Utilities' CAPM model, and Staff's CAPM analysis forms an appropriate basis to determine ROE. Exhibit 1 to the Utilities' Brief on Exceptions makes this calculation, which results in 10.38%. This will form the basis of the ROE calculation.

Taking into account Staff's recommended adjustment to remove the effect of the Utilities' affiliation with unregulated entities, the resulting ROEs for Peoples Gas and North Shore are 10.29% and 10.09%, respectively. Additionally, the Commission deems it appropriate to reduce the Companies' ROEs by ten (10) basis points to reflect the reduction in risk associated with the Rider VBA pilot program. Therefore the Commission finds reasonable and supported by the record the resulting value for ROEs of 10.19% for Peoples Gas and 9.99% for North Shore.

Taking into consideration the Commission's conclusions regarding capital structure, cost of long-term debt, and cost of common equity the Commission finds that Peoples Gas should be authorized to earn a rate of return of 7.76% on its rate base and that North Shore should be authorized to earn a rate of return of 7.96% on its rate base. The tables below show the calculation of those authorized rates of return:

Peoples Gas

Component	Percentage	Cost	Weighted Cost
Long-term debt	44.00%	4.67%	2.05%
Common equity	56.00%	10.19%	5.71%
Total	100.00%		7.76%

North Shore

Component	Percentage	Cost	Weighted Cost
Long-term debt	44.00%	5.39%	2.37%
Common equity	56.00%	9.99%	5.59%
Total	100.00%		7.96%

9. North Shore

Most of the foregoing analysis for PGL applies equally to North Shore. Insofar as North Shore warrants different consideration and/or a different outcome, that has been provided above.

D. Flotation Costs

In his market model analyses, Utilites witness Moul included a standard adjustment for the flotation costs (the underwriting discount and stock issuance expenses) associated with issuing new common stock, namely. Mr. Moul based his nineteen (19) basis-point adjustment on the 3.9% average flotation costs incurred by the utilities in the utility sample during the period 2001-2005. Also, the Utilities state they have previously incurred, but did not recover, flotation costs totaling $485,000 for each company. They argue that if Mr. Moul's flotation cost adjustment is rejected, then the Commission should at least authorize an adjustment that allows recovery of previous flotation costs. NS-PGL Init. Br. at 93.

Staff says flotation costs are recoverable only if a utility can verify both that it has incurred the specific amount of flotation costs it seeks and that those costs have not been previously recovered. Staff charges that instead of using the Utilities' actual flotation costs, Mr. Moul applied a generalized flotation cost estimate based on public offerings of common stocks by gas utilities from 2001 to 2005. Staff underscores that the Commission has repeatedly rejected generalized flotation cost adjustments in previous cases. Staff adds that we rejected North Shores and Peoples Gas' flotation cost adjustments in Docket Nos. 91-0010 and 91-0586. Staff Init. Br. at 75-76.

Staff says that the Utilities' supporting evidence (NS Ex. BAJ-1.3 and PGL Ex. BAJ 1.3 - i.e. Schedule D-5) does not show that a single dollar of the proceeds from the Peoples Gas Energy common stock issuances presented in those exhibits was ever invested in the Utilities, let alone whether any was used for Utility purposes. Staff argues that the burden of proof rests on the utility to prove the reasonableness of the components of the revenue requirement. Staff Rep. Br. at 31-34 (citing Citizens Utility Board v. Illinois Commerce Commission, 276 Ill. App. 3d, 730, 746 (1995)). Furthermore, Staff maintains, even accepting as true that the Utilities incurred flotation costs in the amounts set forth in Schedule D-5, the Utilities merely imply that they have not previously recovered those flotation costs through rates, by referencing several past Commission Orders. However the Commission has stated that the absence of a reference to recovery of such costs in previous orders is not sufficient evidence to support a present adjustment. Docket No. 91-0193, Order at 106 (March 18, 1992,).

According to the City-CUB, Mr. Moul's proposed adjustment for flotation costs violates Commission policy of allowing flotation costs only under very limited circumstances. City-CUB state that Mr. Moul addresses only a generalized adjustment that is not based on specific costs incurred or anticipated by either of the Utilities. City-

CUB Init. Br. at 49-50. City-CUB also emphasize that the Utilities elected to use a test year in which no equity was issued.

City-CUB agrees with Staff that the Utilities have not proven that the equity issuance costs identified in their exhibits are unrecovered. According to the City-CUB, the costs were purportedly incurred fifteen or more years ago. Also, the Utilities, as wholly-owned subsidiaries with no public shares, do not incur such costs directly and the allocation holding company costs among regulated and unregulated affiliates is not addressed by any evidence. Id. at 49; Rep. Br. at 32-33.

Commission Conclusions

The Utilities seek a standard flotation cost adjustment of nineteen (19) basis points, and also request recovery, for each company, of $485,000 of flotation costs purportedly incurred but not previously recovered. The Commission will not accept a "standard" flotation cost adjustment, which fails to reflect the specific circumstances of each individual Illinois utility involved. Further, there is no flotation in the test year, and no specific flotation planned, nor do the Utilities address how the cost of stock issuance by their parent corporation is allocated to their regulated activities.

As for the Companies' allegedly unrecovered prior flotation costs, the record does not support recovery now. In order to qualify for a utility specific flotation cost adjustment, the utility must do more than (for the first time in its brief) identify numbers in its initial filing. Even if this request would not violate the prohibition on retroactive ratemaking, there is no adequate evidence connecting old stock issuances to these Utilities or negating prior recovery.

E. Weighted Average Cost of Capital

1. Peoples Gas

As we stated in connection with Peoples Gas' return on common equity, Peoples Gas' approved weighted average cost of capital is 7.48 %, including 4.67% long term cost of debt and 9.7% return on common equity.

2. North Shore

As we stated in connection with North Shore's return on common equity, North Shore's approved weighted average cost of capital is 7.69%, including 5.39% long term cost of debt and 9.5% return on common equity.

V. HUB SERVICES (All issues relating to Hub services)

A. Manlove Field

The Hub is a group of interstate gas transmission and storage services available to wholesale customers. Hub services are made available by Peoples Gas using portions of the capacity at Peoples Gas' underground storage facility, Manlove Field, and Mahomet Pipeline. The Federal Energy Regulatory Commission approves the

maximum rates that Peoples Gas can charge customers that use these Hub services , and the resulting revenues are credited to retail customers through the purchased gas adjustment clause (Rider 2).

Staff takes the position that there is a substantial risk that the cost of the additional base gas that Peoples Gas is likely to have to add to Manlove Field to support provision of Hub services is greater that the Hub revenues, and thus, is imprudent to operate. As such, Staff would recommend that the Hub be discontinued. City-CUB and the AG do not weigh in on all aspects of the dispute. But, they share a concern and each makes specific recommendations going forward.

The Commission here considers all of the evidence of record and positions taken in the matter.

1. Peoples Gas

Manlove Field, Peoples Gas explains, is an underground aquifer, i.e., porous rock that bears water in the pores. PGL Ex. TLP-1.0 at 3. Its witness observes that Manlove Field is particularly complex, even as aquifer storage fields go. Id. at 4. On the whole, Manlove is large, inefficient (a relatively high percentage of gas becomes trapped), and both difficult to manage and characterize. Id. at 3; Tr. at 472 & 492. All these features and the fact that the field has been used for gas storage operations for years, renders it difficult to ascertain which areas of the aquifer are virgin aquifer and what areas have trapped gas. It is also difficult to determine whether new injections will invade virgin aquifer or previously invaded areas. NS-PGL Ex. TLP-3.0 at 10.

When Peoples Gas introduced Hub services, it did not install additional wells or other facilities to enable it to provide the service. It merely expanded the amount of working gas at Manlove Field by injecting more gas into the storage field and increased working gas by 10.2 Bcf. Staff Ex. 10.0 at 6.

In all, from 1997 through 2006, Peoples Gas states, it capitalized an additional 7.88 MMDth of its Manlove injections as cushion gas. Id. at 11. Based on the various metrics used by Peoples Gas to assess the storage field's performance, this is keeping Manlove Field operating, and as expected. NS-PGL Ex. TLP-2.0 at 7-9.

Peoples Gas explains that it did not inject additional cushion gas at the time it started offering Hub services. What Peoples Gas has done instead is to characterize a percentage of the gas it injects each day during the injection season as cushion gas. PGL Ex. TLP-1.0 at 10. Some of that annual cushion gas allotment is supporting Hub operations, and the rest is supporting general storage operations in Manlove Field. NS-PGL Ex. TLP-3.0 at 6-7. Peoples Gas estimates the amount of cushion gas that would be attributed to the Hub storage to be approximately 1.34 MMDth. NS-PGL Ex. TLP-2.8.

2. Staff's Position

Staff takes the position that Peoples Gas should have, but did not inject more base gas at Manlove Field to support the start of Hub operations. The testimony of Staff's witness Rearden, who relied upon Staff witness Anderson's technical expertise for the technical definitions in his testimony, defines the essential terms for the issue.

He explains that "top gas" (also known as "working gas"), is what is anticipated to be used or cycled in normal operation during the injection or withdrawal season. Staff Ex. 12.0. "Recoverable base," according to Mr. Rearden, is the natural gas that is not normally cycled but which provides pressure in the reservoir to cycle the top gas. Id. And, he further defines non-recoverable base gas as what is trapped in the reservoir and cannot be recovered but what is necessary to support the top gas. Id. Both of the latter constitute and are interchangeably referred to in testimony as "base", "maintenance," or "cushion" gas.

Staff points out that Peoples Gas increased Manlove Field's working gas inventory by 10.2 BcF in order to be able to provide Hub services. To increase the Manlove Field working gas, Staff witness Anderson testifies, Peoples Gas needs to inject gas into the field that cannot be withdrawn. Staff Ex. 10.0. He estimates that base gas needed to increase working inventory is approximately four times the amount of the increase in Manlove Field's working gas. This base gas becomes part of rate base and since base gas cannot be withdrawn, Staff notes that it is treated as a capital investment by Peoples Gas. Staff Ex. 12.0 Revised at 10-11.

Prior to initiating Hub services, Staff reasons that Peoples Gas had to decide whether to either inject the necessary base gas immediately into Manlove or to continually inject base gas. Staff observes that Peoples Gas has chosen to continually inject base gas. While Staff does not disagree that Peoples Gas can operate Manlove in this manner, its decision causes some concern.

Staff maintains that forty years of operating history at Manlove as well as the operation and theory behind all aquifer storage fields, dictate that all working inventory requires base gas. Staff Ex. 22.0 at 24. And, it argues, Peoples Gas failed to demonstrate that its expansion of Manlove's working inventory for Hub operations did not also require an expansion in the volume of base gas.

Staff believes that Peoples Gas' choice to delay the initial injection of the base gas necessary to support Hub operations spreads the cost of that additional base gas out over time, but also creates a situation where the ultimate cost associated with that base gas will increase.

On the basis of its gas cost estimates and calculations, Staff argues, Peoples Gas' decision to not inject base gas when Manlove was first expanded to support Hub services will expose it to a significant cost in the future. Staff maintains that the cost exposure for the future injections of base gas necessary to support the Hub operations should be borne by Hub services and not Peoples Gas' ratepayers. Staff Ex. 22.0 at 32.

Staff takes note of the claim by Peoples Gas that less base gas is needed now than in the past because Manlove Field trapped or retained more initial gas injections than subsequent injections, thus relatively less gas was trapped in more recent injections. NS-PGL Init. Br., at. 95-96. Staff notes too, that PG provided a graph (North Shore/Peoples Ex. TLP-2.6) that shows a 7-year running average of the additional cushion or base gas added to the field since the field began operation. Staff points out that this graph covers two distinct injection paradigms. From 1964 to 1998, Staff notes,

cushion gas was injected only when Manlove Field's performance declined. From 1999 to 2006, however, cushion gas was injected on a continuous basis and recorded as a percentage of volume of the whole-gas injections. As such, Staff observes that Peoples Gas employed different cushion gas injection methodologies in these respective times. But, Staff claims that there is nothing in this information to demonstrate that the maintenance gas needs at Manlove Field will not increase in the future. (Staff Ex. 22.0 at 29-30). And, Staff submits that Peoples Gas' claim that base gas requirements reduce over time, is disputed by its recent need to increase the base gas continuous injection volumes from 2% to 3.5%.

Staff notes that Peoples Gas asserts that its recent decision to increase the percentage of gas injections from 2% to 3.5% does not represent an increase, because there was a metering problem at Manlove caused by pulsations of the compressors. NS-PGL Init. Br. at 97; NS-PGL Ex. TLP-2.5. Peoples Gas believes that it was likely that it was injecting over 3% instead of the 2% injections it thought it was making at the time. In Staff's view, this is mere speculation and should be treated as such.

Staff rejects the notion that the working inventory in Manlove Field can be increased by 10.2 Bcf to provide Hub services without any additional injections of base gas. Staff solidly maintains that all working inventory in Manlove Field, whether for the ratepayer or the Hub, requires base gas to operate. Staff Ex. 10.0, at 17-18. As such, Staff has concerns going forward. Given the lack of studies on the exact volume of base gas required to support Hub operations, Staff created its own analysis and estimated that 45.3 Bcf of base gas was needed to support Hub operations. Recognizing that its methodology provides only a rough estimate in the situation, Staff nevertheless maintains that it shows the obvious disparity between Peoples Gas' claim of zero and the magnitude of the ultimate base gas volumes it believes are needed to support Hub operations. Staff Ex. 10.0 at 21-22.

According to Staff, Peoples Gas never conducted any studies to determine the amount of base gas its Hub operations specifically require. It points out that Peoples Gas' reservoir studies only review the amount of maintenance gas that is continually needed to support the total inventory of Manlove Field. For example, Staff observes that Peoples Gas' study shows Manlove Field now needs 3.5% of injected volumes to support its' performance. NS-PGL Ex. TLP-2.1. Staff believes that this underestimates the need for additional base gas.

In Staff's view, Peoples Gas' own evidence indicates an obvious need for base gas. Staff cites Peoples Gas' witness Puracchio's statement that, "Gas in the Manlove Field reservoir is under pressure and tends to expand, radially invading new areas. As this occurs, some of the gas inevitably becomes trapped as cushion gas." PGL Ex. TPL-1.0 at 10. Staff does not dispute this statement, and observes that this testimony was provided to support the continuous need for maintenance or base gas injections into Manlove in order to maintain field performance over time, not in relation to Hub expansion. Staff's position, however, is that this statement applies for any additional gas injected into Manlove field and including the Hub expansion. Staff Ex. 22.0 at 12-13. In other words, Staff argues, anytime additional gas is injected into Manlove a significant amount of that gas is lost.

Staff refers to Peoples Gas' Ex. TLP-2.1, which it describes as a report that details the information and methodology used to construct a new computer model of Manlove. The result of this study, Staff observes, showed the need to increase the percentage of injections retained as base gas at Manlove from 2% to 3.5%. While Staff does not dispute the need to increase the percentage of injections retained for base gas injection from 2% to 3.5%, it is still concerned that this study could ultimately understate the percentage of injections of cushion gas needed at Manlove.

3. Peoples Gas Response

Peoples Gas asserts that Staff is mistaken in assuming that Peoples Gas expanded Manlove Field's working gas by 8 Bcf all in the first year. In that first year of 1998, it points out, Hub inventory was just 1.5 Bcf, and did not go above 8 Bcf until 2002.

While the cornerstone of Staff's argument is that the sudden large increase of working gas should have been accompanied by a large injection of cushion gas, Peoples Gas explains that the expansion of Hub services was much more gradual. NS-PGL Ex. TLP-2.8. Therefore, it was quite reasonable, says Peoples Gas, to continuously inject cushion gas to support all operations at Manlove Field, as opposed to inputting a single large injection.

Over the forty years Manlove has been in existence, Peoples Gas observes that it has injected a great deal of gas into the field as base gas. This is because gas slowly creeps outward over time, invading new areas. When Peoples Gas began gradually increasing its working gas to enable Hub operations, it was initially able to do so with the support of base gas already underground. To support all storage operations, including both Hub and other storage, Peoples Gas began to add base gas going forward at the rate of 3.5%. This operation, Peoples Gas asserts, has proved adequate to keep the field operating properly.

If the situation were that it is injecting too little cushion gas, Peoples Gas asserts that it would notice, and in a relatively short time, that Manlove was not performing properly. Tr. at 485. In operating an aquifer storage field, Peoples Gas explains, the operator watches various metrics such as pressure and peak deliverability, to see if the field is operating as expected (Tr. at 485-486) and that is just what Peoples Gas has done. When, after fixing a metering problem, Peoples Gas was inadvertently under-injecting cushion gas by a shortfall of just 0.6 MMDth per year, Peoples Gas noticed a significant drop-off in field performance. Then, when Peoples Gas increased its injections to approximate their previous levels, field performance promptly returned to normal. NS-PGL Ex. TLP-2.0 at 7-8. Peoples Gas points to this scenario as proof that, if Staff were correct that Peoples Gas has been severely under-injecting cushion gas, Peoples Gas would see it in the performance of the field. Since field performance has been quite good in the last several years, Peoples Gas maintains that its capitalized cushion gas injections of 7.88 MMDth have been sufficient.

4. Commission Analysis and Conclusion

With respect to the operations at Manlove Field, and the concerns raised by Staff, the Commission must decide whether Peoples Gas has been making sufficient

injections of cushion gas to support its operations. Based on the evidence showing that it has been monitoring field performance, with no fall-off in performance since it has been continuously injecting 3.5% cushion gas, we find that Peoples Gas' cushion gas injections have been reasonable. In total, the capitalized injections since Peoples Gas' last rate case amount to 7.88 MMDth of gas.

Staff is correct that Peoples Gas did not inject new cushion gas to support Hub services at the time it initially began offering those services. At the same time, however, Staff concedes that Peoples Gas could just as well choose to add cushion gas gradually and continuously to support the expanded use of Manlove Field. Staff Init. Br. at 97. In other words, there were two reasonable ways to proceed. The option that Peoples Gas chose was to gradually increase its use of Manlove Field for Hub services, while continuing to inject cushion gas to support the overall operation of the field. According to the record, this appears to be working. There was only a short period during which cushion gas injections were inadvertently decreased and this caused Peoples Gas to notice a drop in field performance. When it increased injections to the correct amounts, however, the field responded quickly and has been operating normally. This performance and the attention to performance is the best evidence. It establishes for the Commission that, in both amount and manner, the cushion gas injections reported by Peoples Gas have been sufficient.

For the purposes of considering Staff's contention that offering Hub services at Manlove was imprudent, the Commission finds that Peoples Gas' calculation of 1.34 MMDth of the total 7.88 MMDth of cushion gas injections is reasonable. NS-PGL Ex. TLP-2.8 provides this calculation, and is the only credible evidence in the record. The Commission finds Staff's calculation that the Hub required 45.3 Bcf of base gas, based on the "historical ratio" of working gas to base gas, to be not reasonable under the entirety of the facts and circumstances borne out by the record.

B. Hub Services

1. Peoples Gas

Peoples Gas explains that Hub services are comprised of two types of FERC-jurisdictional services. First, the Hub includes the transportation and storage provided by Peoples Gas pursuant to a FERC Operating Statement. Second, it includes other interstate services provided pursuant to FERC's rules authorizing sales for resale at negotiated rates. NS-PGL Ex. TZ-2.0 at 65.

Peoples Gas points out that it received a Hinshaw Blanket Certificate in March, 1998. The Peoples Gas Light and Coke Company, 82 FERC ¶62,145 (1998). And, the initial Operating Statement which included only transportation services was approved by the FERC in March, 1998. The Peoples Gas Light and Coke Company, 82 FERC ¶61,239 (1998). The FERC approved the filing with storage and parking and loaning services in March 1999. The Peoples Gas Light and Coke Company, 86 FERC ¶61,226 (1999). Service began immediately following the receipt of the operating approval. Id. at 66.

Hub rates associated with the services provided under the Operating Statement are developed and set according to the FERC rules. The most recent rates were

established in FERC Docket No. PR07-1-000 and approved by FERC in March, 2007. The Peoples Gas Light and Coke Company, 118 FERC ¶61,203 (2007); *See* also NS-PGL Ex. TZ-2.0 at 66. The rates for the other Hub services are established through negotiations with the counter parties and by means of a competitive bidding process in which the highest bidder wins. Id. at 66; Tr. at 512.

Peoples Gas points out that it has credited to the Rider 2 Gas Charges(or will be crediting following an order in its fiscal 2005 cost reconciliation case), over $20 million in 2005 and 2006 alone, for gross revenues from the Hub. In addition, as part of the resolution of Peoples Gas' fiscal years 2001-2004 Gas Charge case, the Commission determined that issues concerning the treatment of Hub revenues for those years were properly included in the refund that the Commission ordered. Peoples Gas would further note that Hub revenues are forecasted to reach $13 million in 2007. NS-PGL Ex. TZ-2.0 at 69-70; Tr. at 516.

2. Staff

Staff recommends that the Commission order Peoples Gas to cease providing Hub services because the provision of Hub services at Manlove Field is likely to impose costs above revenues upon ratepayers in the coming years. Based on its review, Staff contends that the costs for base gas needed to grow the working inventory gas at Manlove Field are substantial. In this regard, Staff questions the prudency of starting Hub services without a complete analysis and assessment. Peoples Gas examined whether it could expand Manlove Field, but it never estimated the costs, how long it would take, or whether ratepayers would benefit from the expansion.

Staff observes Peoples Gas to assert that there are customer benefits from its provision of Hub Services. And, Staff concedes that Peoples Gas is crediting revenues that are higher than costs currently being incurred. NS-PGL Init. Br. at 102. Still, it argues that these revenues are insufficient to justify continued Hub operations, because in Staff's view, the revenues are likely to be overwhelmed by a need for massive investments in base gas. Staff Init. Br. at 86. Staff witness Rearden's net benefit analysis for "revenues greater than costs" included the costs of base gas, that, have not been realized as yet, but which Staff views as likely to be incurred in the future. Id. at 31.

Further, Staff disputes Peoples Gas claims that the Hub expansion extended Manlove's decline curve and that this extension benefits the ratepayer. Staff Ex. 22.0 at 34-35. According to Staff, Peoples Gas provides no studies or other documentation to support this statement. Notably too, Peoples Gas made the same claim in Docket 01-0707, which the Commission rejected.

Staff also commented on Peoples Gas claim that additional liquidity lowers prices: "[i]ncreasing market liquidity by increasing the supply of gas at the Chicago city gate creates downward pressure on gas prices." NS-PGL Init. Br. at 100. Staff argues that this unsubstantiated statement provides no compelling reason to allow Hub services to continue. In Staff's view, the extent to which the Hub adds 'liquidity' to the market is just not clear. Various publications calculated price indices before the Hub was operational, it notes, so a market already existed. Even if the Hub adds some

degree of liquidity to the market, Staff does believe that this necessarily lowers prices. According to Staff, the best that can be said is that additional liquidity lowers transaction costs, which makes the price signal more valuable. But, in Staff's view, prices themselves are determined by the interaction of supply and demand, and additional liquidity, by itself, does not alter that balance.

Staff states that it is only concerned with whether ratepayers are better off with the Hub or without it, i.e., whether the Hub, including all of its associated costs, is prudent. To this end, Staff conducts a net benefits test. If the result is a negative net benefits (Hub benefits are less than its costs), then ratepayers are subsidizing Hub customers, since ratepayers are covering costs caused by Hub customers. Taking into account Staff's view that Peoples Gas may need to inject up to 36 Bcf of base gas Staff calculates that reasonable estimate for the total annual pre-tax cost for base gas is $11.3 million. Id. at 24-25. And, Staff observes that Peoples Gas to calculate its historical expenses at approximately $2.0 million. Id. at 25. On these factors, Staff witness Rearden estimates that the incremental cost of the Manlove Field expansion in 1998 totals approximately $13.3 million. Id. at 26.

Further, in examining the fiscal year Hub revenues over time, Dr. Rearden determined that $10-$12 million was a reasonable estimate for Hub revenues. Id. at 22. He also considered Peoples Gas calculation that $8.9 million out of $10.1 million (88%) of total Hub revenues were directly connected to the Manlove expansion. NS-PGL Ex. TZ-3.6.

Dr. Rearden also tested whether the Hub is prudent beginning from today's situation, given Staff's view about how much base gas Peoples Gas will ultimately have to add to Manlove Field. By Staff's account that totals 45 Bcf and since Peoples Gas has already added about 8 Bcf, it still is potentially liable for an additional estimated 37.4 Bcf. This amount calculates at total annual costs of approximately $16 million. Under this scenario, and owing to Peoples Gas claims that revenues are likely to run to less than $12 million, Staff maintains that the Hub cannot hold ratepayers harmless. Even at that, Staff observes the $4 gas cost to be at the low end of what is reasonable in today's gas market. At higher gas prices, like the $6 and $8 levels that Dr. Rearden considered for his study, the cost to inject base gas into Manlove Field increases and suggests that the Hub is unlikely will be able to pay for itself going forward. Under all the variables used for his study, Staff argues, Dr. Rearden concluded that the Hub is uneconomic for ratepayers. Staff Ex. 24.0 (Corrected) at 27.

Staff claims that, before Peoples Gas expanded Manlove Field, it did not examine the value that the extra capacity might provide to ratepayers as a physical hedge and for peak day deliverability. Rather than using the system to generate Hub revenues, Staff believes that the system could be used to decrease ratepayers' gas costs. In Staff's view, increasing Manlove Field's allocation to ratepayers might enable the Peoples Gas to substitute Manlove Field storage for leased storage and/or transportation services. Staff Ex. 24.0 Corrected at 29.

Staff notes that, in surrebuttal testimony, Peoples Gas did present a study that purported to investigate whether the additional capacity (10.2 Bcf or MMDth) benefitted ratepayers more by using it to offer Hub services or to physically hedge gas for

ratepayers. Staff observes this study to reflect Peoples Gas estimate that the physical hedge is worth $9.3 million, while it forecasts Hub storage revenues (those resulting from the expanded Manlove Field) equal to $10 million. In addition, there is the position that, if the 10.2 Bcf (MMDth) additional capacity in Manlove Field can be used to store gas for ratepayers, Peoples Gas must earn a return on the expenditures for the increased gas volumes. NS-PGL Ex. TZ-3.0 at 40.

While the figures derived from the two options are roughly of the same magnitude, Staff does believe them to be directly comparable. According to Staff, revenues of $10 million does not correspond to the total value of Hub storage services to Hub customers, but represents some fraction (not determined, since it is a function of the market) of the value of the physical hedge. In other words, Staff maintains, the physical hedge value is likely to be split between the customer and Peoples Gas as the Hub services provider. In Staff's view, either the $9.3 million amount underestimates the physical hedge, or the Hub revenues of $10 million is not a realistic amount or tied to other years with a different seasonal price differential.

Referring back to the tests it produced, Staff claims to have demonstrated that costs are higher than revenues, and that the revenue shortfall from Hub services will be ultimately borne by ratepayers. As such, Staff argues, Peoples Gas should cease Hub transactions. Id. at 34-35.

Staff notes that City-CUB's main point about the Hub appears to be that Peoples Gas should stop their practice of predetermining a portion of Manlove storage capacity to be used for the Hub before it optimizes its gas supply portfolio. City-CUB Init. Br. at 54. Staff agrees that the Manlove Field's working inventory should not be allocated for Hub Services before determining the optimal allocation to ratepayers. Staff further believes that the total of 7.88 Bcf (MMDth) volume of base gas, valued at $39,019,000 should be denied rate base treatment. In addition, Staff recommends that Peoples Gas' reported Hub expenses should also be disallowed from rates. In Staff's view, these are not shown to be just and reasonable.

Were the Commission to not find any imprudence in the expansion of Manlove Field, Staff claims that the cost associated therewith should still fail recovery. This is so, Staff argues, because Peoples Gas did not obtain prior Commission approval for its actions as required under Section 7-102(E) of the PUA. 220 ILCS 5/7-102(A)(g). Staff claims that a number of legal opinions support its position on the matter. Staff Init. Br. at 64-70.

3. City-CUB

In this proceeding, CUB and the City sponsored the testimony of Jerome Mierzwa of Exeter Associates, Inc., regarding Peoples Gas' provision of Hub services and its operation of Manlove field. They point out that the issues here are essentially identical to the issues Mr. Mierzwa addressed in Peoples Gas' 2005 reconciliation proceeding, i.e., Docket No. 05-0749. City-CUB further point out that, in Docket No. 05-0749, Peoples Gas explained that the amount of Manlove storage it assigns to system supply is based on historical experience and while the utility uses a gas planning dispatch model in its gas supply planning process, it predetermines the 26.3 Bcf of

storage it allocates to system supply and excludes the 10.2 Bcf it uses to provide Hub services from its gas dispatch planning model. City-CUB Ex. 3.0 at 4, 7. In Docket No. 05-0749, Mr. Mierzwa recommended that Peoples Gas "should optimize the entirety of Manlove field's storage capacity for ratepayers by including all available storage in the gas dispatch model." *See* Id. at 7.

Here, City-CUB note, the use of Manlove Field for Hub services also is at issue and they observe Staff to recommend that Peoples Gas cease offering such services. Staff Ex. 24.0 REV. at 29. They note too, that Staff recommends that the Commission disallow the $35 million of base gas that Peoples Gas seeks to include in rate base, as well as $2.5 million in operational expenses. Id. at 25.

If Hub services were no longer offered, City-CUB point out, sales customers would no longer be credited for the approximately $10 million in Hub revenues in any future purchase gas adjustment ("PGA") proceedings. City-CUB further raise the point that, if the Commission were to determine that Hub services should be terminated, it will need to decide the appropriate disposition or use of the 10.2 Bcf of working gas currently assigned to the Hub.

For their part, City-CUB recommend that the Commission preserve, in this proceeding, its ability to determine the extent to which Manlove storage should be used to serve system supply in gas cost reconciliation proceedings – both current and future. While they take no position on Staff's recommendations with regard to the Hub, City-CUB ask the Commission not to foreclose options for the use or disposition of that asset before PGL completes an optimization study that is not compromised by a predetermined assignment of capacity to the Hub. That determination is best made, they argue, in the context of Peoples Gas' pending and future PGA proceedings.

Essentially, City-CUB want Peoples Gas to optimize storage for ratepayers. As such, they contend that Peoples Gas's practice of predetermining a portion of Manlove storage capacity to be used for Hub services is not reasonable because it denies ratepayers the full potential benefits of the storage capacity for which they pay in base rates. City-CUB Ex. 3.0 at 7. Their witness, Mr. Mierzwa testified that, "[a]ll else being equal, theoretically, the more storage available to a gas utility, the lower the utility's gas costs." Id. at 5. Further in his testimony, City-CUB observe, Mr. Mierzwa demonstrated that in using the current seasonal difference in gas prices as reflected on the New York Mercantile Exchange ("NYMEX") of approximately $1.20 per Dth, Peoples Gas could potentially reduce its gas costs by $12.24 million by taking advantage of the seasonal differences in gas prices. City-CUB Ex. 3.0 at 6. This calculation, they note assumes that the entire 10.2 Bcf currently assigned to Hub services were utilized for system supply. As another alternative, City-CUB note, Mr. Mierzwa calculated the effect of using the 10.2 Bcf of Manlove capacity currently assigned to Hub services to displace the same amount of leased storage. Id. at 6. His work (reflected in City-CUB Ex. 3.2), demonstrates that, since Peoples Gas currently purchases 33.5 Bcf of contract storage service from interstate pipelines at an average cost of approximately $1.00 per Dth, the

Company could potentially reduce its gas costs by $10.5 million if it used existing Manlove storage assets instead. Id.

City-CUB observe that Utilities' witness Zack disputed Mr. Mierzwa's calculations, averring that (1) his calculation of using the entirety of Manlove for ratepayer gas excludes inventory costs of the additional 10.2 Bcf of gas inventory which, if applied, would reduce his estimate of savings by $4.96 million for a net ratepayer benefit of $7.28 million; and (2) the displacement of leased storage inaccurately assumes a one-for-one replacement. NS-PGL Ex. TZ-3.0 at 45-46. And, Mr. Zack further claimed that leased storage provides additional benefits in the form of injection and withdrawal flexibility. Id. at 40-41. According to City-CUB, however, Mr. Zack's criticisms ignore Mr. Mierzwa's qualification that, while the entire 10.2 Bcf of Manlove storage assigned to Hub services cannot provide both a $12.24 million seasonal price benefit and a $10.5 million reduction to contract storage costs, the 10.2 Bcf could be used to partially obtain both benefits. For example, he indicated that 5.0 Bcf of Manlove storage could be used to provide a seasonal price benefit, while 5.2 Bcf could be utilized to displace contract storage. City-CUB Ex. 3.0 at 6.

To be clear, City-CUB point out that Mr. Mierzwa did not recommend that all of the Manlove storage currently used to support Hub services should be assigned to system supply - only that the amount of Manlove storage assigned to system supply should be determined by the utility's gas dispatch model. Id. at 7. So too, they argue, the purpose of Mr. Mierzwa's analyses was not to show that the entirety of Manlove should be used for system supply or to determine a disallowance, but only to support the premise that the optimal amount of storage should be determined through Peoples Gas' existing gas dispatch planning model, rather than being predetermined. Id. at 7.

City-CUB recognize that any revenues Peoples Gas receives by providing Hub services flow through the gas charge. And, they note Mr. Zack to claim that, during each of 2005 and 2006, Hub revenues exceeded $10 million. NS-PGL Ex. TZ-2.0 at 70. Their witness Mr. Mierzwa testified in the 2005 reconciliation period at issue in Docket No. 05-0749 that Hub revenues exceeded the increase in gas costs for sales customers that resulted from the reservation of Manlove storage capacity for Hub services. Docket No. 05-0749; City-CUB Ex. 1.0 at 9.

Under City-CUB's suggested approach, Peoples Gas could continue to utilize Manlove Field to provide Hub services, and thus any future revenues from those services would continue to flow through the gas charge and customers would continue to receive that benefit. Their only argument is that Peoples Gas does not justify its practice of eliminating the 10.2 Bcf of gas reserved for Hub services from the gas dispatch planning model. Therefore, these parties recommend that the Commission require Peoples Gas to optimize the entirety of Manlove Field's storage capacity for ratepayers by including all available storage in the gas dispatch model. This, they argue, will have the effect of reducing gas costs for ratepayers.

In response to concerns about the use and cost of the Hub, City-CUB note Mr. Zack to have considered three options that "represent the opportunity cost of the Hub."

NS-PGL Ex. TZ-3.0 at 39. First, he indicated that Peoples Gas could eliminate the 10.2 Bcf currently assigned to Hub services altogether and return field operations to a 26 Bcf annual cycle. Id. Second, he considered that the Company could use some or all of the 10.2 Bcf of Hub capacity for customers without reducing any leased storage. Id. Third, he explained that the Company could use some or all of the 10.2 Bcf of Hub capacity for customers, while also reducing, as possible, any uneconomic, leased storage. Id. It is this third option, City-CUB point out, that most closely resembles what their witness Mierzwa is recommending both in this proceeding, and in testimony for Docket No. 05-0749.

With respect to this third option, City-CUB note Mr. Zack's testimony stating that costs and savings would be more difficult to quantify under the third option than under the other options. Id. at 40. But, he also stated that Peoples Gas plans to conduct analyses with regard to determining the most economic use of Manlove storage and the Hub for the benefit of ratepayers. Tr. at 540. And, Mr. Zack further set out that the gas dispatch model would be made part of this analysis. Id. at 541. According to City-CUB, the whole of these affirmative statements, favorably address the very issues they have identified. In the end, they assert, if the Commission directs Peoples Gas to conduct the analyses described by Mr. Zack during his cross-examination, i.e., to use the gas dispatch model to optimize use of Manlove field on behalf of its sales customers, City-CUB's concerns regarding the appropriate use of the storage field in both the instant dockets and Docket No. 05-0749 may be resolved.

4. Peoples Gas' Response

Peoples Gas observes Staff to argue that it was imprudent for Peoples Gas to offer Hub services and that the cost of expanding the Hub services should not be recovered in rates because Peoples Gas never conducted written studies to determine the prudence of expanding of Manlove Field and never received prior approval from the Commission pursuant to Section 7-102(A)(g) of the PUA before expanding the Hub.

Contrary to what Staff contends, Peoples Gas maintains that the evidence amply demonstrates that the customer benefits provided by the Hub have exceeded, and are expected to continue to exceed, the costs of providing the service. NS-PGL Ex. TZ-2.0, NS-PGL Ex. TZ-3.0 REV. The Hub operation in the fiscal 2006 test year, it points out, brought $10 million in revenues (all credited to the Gas Charge) against an annual revenue requirement of $3.3 million. NS-PGL Ex. TZ-2.0 at 71. Surely, PG argues, this is not the result of imprudence.

Peoples Gas explains that it offers Hub service as a means to more efficiently utilize the existing Manlove Field and Mahomet pipeline assets and to provide customer benefits. Indeed, Peoples Gas asserts, Hub services provide customer benefits in three ways: (1) through credits to the Gas Charge (as discussed above); (2) by extending the Manlove decline point (as defined below); and (3) by increasing market liquidity at the Chicago citygate. NS-PGL Ex. TZ-2.0 at 66.

Peoples Gas explains why it is beneficial that the additional Hub volumes serve to extend the decline point. According to the Utility, extending the decline point of

Manlove means extending the capability of the field to perform full peak withdrawal throughout the winter season. The operation of the Hub causes the injection of more gas into Manlove Field, which extends the field decline point and this, in turn, extends how long into the withdrawal season Manlove Field is useful for storage and capable of full peak withdrawal. Since all Hub volumes are contractually required to be withdrawn, Peoples Gas notes, these bring with them the benefit of the higher volumes without the risks associated with a warm winter. NS-PGL Ex. TLP-2.0 at 13.

To verify the Manlove Field decline point, Peoples Gas notes that a report prepared by Roxar, Inc., in July, 1999 shows the decline point extending as working gas is increased. NS-PGL Ex. TLP-2.9. Also, Peoples Gas points to the 2003 and 2005 Connaugton Reports, each of which contain a discussion of the extension of the decline point. NS-PGL Ex. TLP-2.0 at 14; PGL Ex. TLP-1.1. The critical benefit to ratepayers from this feature, Peoples Gas argues, is well supported and comes in the form of access to the full daily peak withdrawal capability of Manlove Field longer into the winter season.

Contrary to what Staff would suggest, Peoples Gas notes that the Commission never did find that the decline point had not been extended through the additional gas associated with the Hub, nor did it make any finding regarding whether the decline point extension was an operational benefit. Peoples Gas explains that the Commission's finding on the decline point was that the additional gas which supported the decline point extension did not directly benefit customers because the profits from the third party services were not being passed to customers. Docket No. 01-0707, Final Order at 93 (March 20, 1996).

Still another benefit from Hub, Peoples Gas argues, flows from its increasing market liquidity at the city gate specifically and more generally in the Chicago area market. According to Peoples Gas, all the gas supporting Hub activity must come to one of Peoples Gas' city-gate locations to be a Hub transaction. This increases the amount of gas delivered to Peoples Gas on a daily basis. The more gas brought to the Chicago city gate as a result of the operation of the Hub, PG maintains, the greater the benefit to all customers. This activity provides all customers access to a greater amount of gas than would otherwise be available if there was no Hub activity. NS-PGL Ex. TZ-2.0 at 70. Increasing market liquidity, Peoples Gas asserts, creates downward pressure on gas prices.

Since coming into existence, all of Hub expenses, including and consisting primarily of over $7 million of incremental compressor fuel costs have been borne by Peoples Gas. Peoples Gas emphasizes that none of these costs were paid by Peoples Gas' customers. Id. at 69. Peoples Gas explains that the Hub rate design included Manlove Field's base gas requirements and these costs were included in the cost of service study used to support the Hub filing before the FERC. The Peoples Gas Light and Coke Company, 82 FERC ¶ 62, 145 (1998); 82 FERC ¶ 61, 239 (1998); 86 FERC ¶ 61, 266 (1999); 118 FERC ¶61,203 (2007). These costs were then used to develop the rates for Hub services under the Operating Statement. Id. at 68. Peoples Gas flatly states that the expansion of Manlove Field did not involve the use of Gas Charge assets or the use of assets in which costs were being recovered through base rates. All

incremental expenses associated with the Hub, the Utility notes, were absorbed by Peoples Gas. NS-PGL Ex. TZ-2.0 at 67.

Peoples Gas points out that the storage expansion for the Hub began years after Peoples Gas' last rate case. Thus, the base rates approved in Peoples Gas' last rate case proceeding, i.e., Docket No. 95-0032, reflected a test year that was prior to the expansion of Manlove Field. Id. *See* also NS-PGL Ex. VG-2.0 at 57. As such, Peoples Gas seeks to recover these costs through the instant rate hearing.

Peoples Gas considers Staff's proposed disallowance of all costs associated with the Hub to be improper. It observes Staff witness Rearden to recognize that the Hub revenues are estimated to be $10-$12 million per year. Staff Ex. 12.0 at 22. By use of an improper methodology, Peoples Gas argues, Dr. Rearden concluded that Hub costs per year were $13.3 million, as being made up of the capital costs of the supposed additional cushion gas, and operations and maintenance expense. Id. at 12. Since $13.3 million is more than $10-$12 million, he concluded that the Hub is imprudent. Even if it were possible to accept Dr. Rearden's figures, which Peoples Gas does not, the revenue requirement should only be reduced by $1.3 million to $3.3 million per year, as this represents the difference between the cost of $13.3 million and the revenues of $10-$12 million dollars. Yet, Peoples Gas observes that Dr. Rearden would eliminate all the rate base and operations and maintenance expense associated with the Hub, while at the same time leaving in all the revenues to reduce future gas costs. Id. at 30. If the Commission were to find the Hub imprudent, Peoples Gas asserts, then the only proper result is to reduce the revenue requirement no more than $1.3 – $3.3 million. *See* NS-PGL Ex. 2.0 at 71. When imprudence is found, Peoples Gas argues, only its incremental impact, if any, is disallowed. In re Central Ill. Light Co., Docket No. 94-0040, Order (December 12, 1994).

Peoples Gas states that, prior to the Commission's final order in Docket No. 01-0707, all the costs and revenues associated with the Hub and the base rate assets that support the Hub are accounted for above the line. Subsequent to the Docket No. 01-0707 order, however, all the revenues were flowed through the Gas Charge. NS-PGL Ex. TZ-2.0 at 70. Since the Hub came into existence, PG emphasizes, all of its expenses, including and consisting primarily of over $7 million of incremental compressor fuel costs have been borne by Peoples Gas and none of these costs were paid by Peoples Gas' customers. Id. at 69. Peoples Gas maintains that the only incremental capital cost attributable to the Hub is for cushion gas which is discussed in arguments on Manlove Field.

Peoples Gas maintains that the customer benefits provided by the Hub have exceeded, and are expected to continue to exceed, the costs of providing these services. For this reason, Peoples Gas asserts, it should continue to provide Hub services for the benefit of its customers. NS-PGL Ex. TZ-3.0 Revised at 43. When asked what a net benefit to ratepayers is as it pertains to the Hub, Staff Witness Dr. Rearden's response was, "[r]evenues of – either cost savings or revenues greater than costs". Tr. at 674. Using Staff's simple definition, Peoples Gas believes it clear that Hub operations are a net benefit to the Peoples Gas system and its ratepayers.

Peoples Gas observes Staff to claim that cost recovery should be barred owing to Peoples Gas' failure in obtaining the approval required by Section 7-102(A)(g) of the Act. For its part, Peoples Gas maintains that its provision of Hub services did not require approval action under Section 7-102(A)(g). The plain language and specific terms of this statute, Peoples Gas asserts, simply do not apply. While Staff attempts to suggest that Hub services are unconnected to "the business of such public utility" in order to have the statute apply, Peoples Gas strongly disagrees and explains why. If Hub services were not part of the utility business, Peoples Gas argues, it seems unlikely that the Commission could or would have ordered revenues to go to utility customers through the Gas Charge. But, Peoples Gas points out, that is precisely what the Commission did in the Peoples Gas 2001 Reconciliation docket.

Peoples Gas notes too, that Hub services were no secret and certainly not to Staff, and it details Staff's involvement in matters over the years which reflects that full and long-time knowledge. Further, Peoples Gas argues, all of the case authority on which Staff relies can be easily distinguished because the facts and circumstances here are much different. In short, it takes issue with Staff's position.

Peoples Gas observes Staff to contend that Peoples Gas has failed to prove that its costs of operating the Hub are just and reasonable, such that those costs should be removed from Peoples Gas' rate base. It is well-established on record, Peoples Gas asserts, that the Hub is a net benefit to the utilities' customers. Its costs are prudently incurred and are used and useful in serving customers.

5. Commission Analysis and Conclusion

On the whole of the record before us, and on this date, the Commission is unable to find that the expansion of Manlove Field is imprudent. We have already considered that Peoples Gas has been injecting base gas in amounts sufficient to support Manlove Field's operation and this includes storage for sales customers, services to its transportation customers and FERC-jurisdictional Hub operations. There is no evidence to persuade us otherwise.

Staff's position that Hub services are imprudent and its conclusions in the matter are based upon what derives from its net benefits test. While we understand that such an analysis is useful and telling, we also believe that it must be conducted properly and fairly. All the tests we see here begin with the same faulty premise, i.e., the unproven fact that Manlove Field needed (in 1998), or needs today, 45 Bcf of base gas. In other words, Staff's arguments as well as the inputs for its calculations rely on speculation that massive amounts of base gas into Manlove will be needed in the future. We cannot accept that assumption, however, because the evidence today does not reveal this to be fact. So all we have for the net benefits analysis are a series of sterile mathematical calculations neither grounded in observation of performance nor aided by the requisite scientific expertise. This type of analysis will not serve us in these premises and must be rejected. The bottom line is that we do not find the imprudence on which Staff hinges its position.

Considering all of the relevant evidence at hand, the Commission is persuaded that, at this time, the Hub provides more benefits than costs. We come to this

conclusion by examining all of the relevant evidence. The record shows that Hub revenues have exceeded $10 million annually and they are expected to exceed that amount in 2007. NS-PGL Ex. TZ-2.0 at 70. It is uncontested that, pursuant to the Commission' Order in Docket 01-0707, all revenues from Hub services are credited to Peoples Gas' customers through reductions its Rider 2 Gas Charges, including a gross $20 million in 2005 and 2006 and a forecasted gross $13 million in 2007. NS-PGL Init. Br. at 99. And, the Commission is compelled by the record to find that Peoples Gas has and is complying with our order by crediting to Rider 2 gross revenues from the Hub. In light of this monetary benefit, the Commission believes that it would be harmful to customers to eliminate the Hub.

Other evidence leads the Commission to conclude that the Hub benefits Peoples Gas' customers in a less direct but equally meaningful way. As such, Peoples Gas informs that additional Hub volumes serve to extend the decline point at Manlove Field and this enables the field to perform better. While Staff claims that this attribute is not supported, we find that independent studies of record, i.e., the Roxar, Inc., report of 1999 and the Connaugton Reports of 2003 and 2005, have not been challenged, and these indicate an extension of the decline point. On this evidence, the Commission is persuaded that the extension of the Manlove Field decline point is a benefit of Hub and this benefit is extends to all customers of Peoples Gas.

The Commission also considers the assertion that the Hub activity increase liquidity at the Chicago-city gate and as a result of such activity and the availability of more volumes of gas, there is a theoretical downward pressure on gas prices due to the Hub activity. While Staff disagrees, the evidence does suggests there being some likelihood of downward pressure created because of Hub activity and from this we gather there is benefit to all customers.

The Commission also observes that under a proper allocation of the cost of the base gas supporting Hub operations, the Hub's revenues easily exceed costs. NS-PGL Ex. TZ-2.07. We are mindful that the cost of base gas is shared by Hub customers, but all of the revenues are being credited to the customers through the Purchased Gas Adjustment. NS-PGL Ex. TZ 2.0 at 68. Staff would minimize this tangible benefit that even all of the GCI parties acknowledge to exist.

There is not, nor can there be, any concern of Gas Charge assets being used to subsidize Hub services. The record makes clear and it is unchallenged that all of the Hub expenses, including and consisting primarily of over $7 million of incremental compressor fuel costs have been borne by Peoples Gas. None of those costs are recovered through the Gas Charge and none were paid by Peoples Gas' customers. NS-PGL Ex. TZ-2.0 at 69. The Commission finds the record devoid of any evidence that Peoples Gas has utilized any of the Gas Charge assets to subsidize Hub services. We observe too, that the storage expansion for the Hub began years after Peoples Gas' last rate case. As such, the base rates approved in Peoples Gas' last rate case proceeding, i.e., Docket No. 95-0032, reflected a test year that preceded the expansion of Manlove Field.

Staff recommends that the base gas cost of $39,018,791.41 that Peoples Gas is proposing be wholly disallowed. In addition, Staff recommends that the Utility's reported

Hub expenses also be disallowed. In other words, Staff would assign all revenues to ratepayers and none of the reasonable costs incurred. We are not comfortable with this one-sided view. So too, Staff's proposed disallowance lacks clarity and conviction. In large part, the premise of Staff's entire argument is that Peoples Gas *has not injected enough base gas* into Manlove Field. At the same time, however, Staff's proposed disallowance would have Peoples Gas not put *any* base gas into rate base. There is a fundamental inconsistency here that cannot be reconciled. It amounts to overreaching.

Recognizing that the Commission might not find imprudence in the decision to expand Manlove Field for Hub services, Staff argues that Peoples Gas' failure to apply for Section 7-102(A)(g) should result in the denial of cost recovery. We do not agree.

The Commission seriously questions that Peoples Gas was required to acquire prior approval to expand working gas at Manlove Field. As we read Section 7-102(A)(g) of the Act, a public utility must obtain approval from the Commission before it may employ its public utility resources in "any business or enterprise" that is not "essentially" and directly connected with or a proper department of division of the utility business. This statute would only be applicable to the Hub if it were unconnected to distribution, storage and sale of gas, i.e., "the business of such public utility." Based on what is on record, that is not the situation here.

We need not bother with a full statutory construction because there is more at hand and it is of dispositive legal significance. Staff fails to recognize that the Commission took close consideration of Peoples Gas' Hub services in Docket No. 01-0707. In that proceeding, we issued certain directives to the Utility as to the proper accounting for the costs and revenues. By our actions, the Commission has effectively provided approval and both we, and People Gas, are bound to that Order in Docket No. 01-0707. Considered in still another way, our actions amount to a waiver of approval as is also within the authority that Section 7-102(A) provides.

We observe that during fiscal years 1997 through 2006, Peoples Gas capitalized an additional 7.88 MMDth of injections as cushion gas into Manlove Field, at a cost of $39,019,000, which it now proposes to include in rate base. Id. at 11. We further note that Peoples Gas has estimated that the amount of cushion gas attributable to Hub services is 1.34MMDth. In the final analysis, the Commission concludes that $39,019,000 will be included in rate base together with $2,533,000 of operations and maintenance expense.

C. Hub Procedures - Manlove Capacity Standards

1. Staff

Staff raises a concern that Peoples Gas has increased its leased storage capacity volumes while at the same time reducing its own allocation of Manlove storage capacity in favor of the Hub. Staff Ex. 23.0 at 14. On the basis of this account, Staff recommended that Peoples Gas develop procedures to document how it allocates capacity from the Manlove storage field and how it ensures that rate payers are not harmed by its decision. Id. Staff further recommended that Peoples Gas provide this

information to the Director of the Energy Division within 60 days of the Commission's Final Order in this proceeding. Id.

2. Peoples Gas

Peoples Gas agreed to Staff's proposal, but it requested 120 days instead of the 60 days recommended by Staff. NS-PGL Ex. TEZ-3.0 at 38. It notes that this date change is acceptable to Staff. Thus, Peoples Gas observes, it is uncontested that it will provide to the Director of the Energy Division within 120 days of the Commission's Final Order in this proceeding, procedures to document how it allocates capacity from the Manlove storage field and how it ensures that rate payers are not harmed by its decision.

3. City-CUB

In their joint brief**,** City-CUB note with particularity the testimony of Peoples Gas witness Zack and his statement that the Utility plans to conduct analyses with regard to determining the most economic use of Manlove storage and the Hub for the benefit of ratepayers. They further point to Mr. Zack's claim that the gas dispatch model would be made part of this analysis. Id. at 541. These parties explain to the Commission that if Peoples Gas were directed and required to conduct the analyses described by Mr. Zack, i.e., using the gas dispatch model to optimize use of Manlove field on behalf of its sales customers, City-CUB's concerns about the appropriate use of the storage field would be resolved.

4. AG Position

The AG recognizes that while the Commission typically does not dictate the precise way in which utility assets are to be utilized, some involvement appears to be required in this situation. In particular, the AG observes City and CUB to have identified that use of Manlove Field as a way to reduce gas costs for ratepayers has never been sufficiently analyzed. At the heart of the AG's proposal is to have Peoples Gas explore the possibility of devoting the entirety of Manlove field to sales customer service; or using some capacity for sales customers while also reducing leased storage; or using some Hub capacity for sales customers without reducing leased storage. According to the AG, these are the same concepts that the City and CUB support. In addition, the AG would have the Utility consider whether the gas dispatch model or another mechanism will better optimize ratepayer interests.

Further, the AG asserts, that Peoples Gas should continue to account for all Hub revenues and non-tariff revenues in accordance with the Commission's order in Docket No. 01-0707, and in compliance with 83 Ill. Admin Code 525.40(d), unless and until ordered to do otherwise by the Commission.

5. Commission Analysis and Conclusion

Based on the recommendations of Staff, the Commission orders Peoples Gas to submit to the Director of the Energy Division, a report of procedures to document how Peoples Gas allocates Manlove storage capacity; how it ensures that ratepayers are not

harmed by its allocation decisions; and, how it will use the gas dispatch model to optimize use of Manlove Field on behalf of its sales customers.

Everything that is set out by the City-CUB and the AG tells us that Staff's proposal is reasonable and necessary to satisfy all of the GCI parties' concerns in these premises. As agreed to between Staff and Peoples Gas, this document will be submitted by the Utility no later than one hundred-twenty (120) days from the date of the Commission's final Order in this proceeding.

After Staff completes its review, it will inform the Commission further.

D. Hub Revenue Distribution Proposal

1. Vanguard, RGS, IIEC.

In their respective briefs, Vanguard, RGS, and IIEC maintain that Hub revenues should not be credited solely to sales customers, i.e., PGA customers. Taken as a whole, the issues they raise are whether the Utilities should credit transportation customers and "Choices For You" customers with the benefit of Hub revenues. No testimony in support of their respective positions is on record.

2. Peoples Gas

Peoples Gas takes no position on the matter and is willing to dispose of the revenues as directed by the Commission so long as this direction is clear and unambiguous. Peoples Gas notes, however, that it would need to develop a mechanism to accommodate a change in the status quo. In this respect, Peoples Gas asks to be able to develop a mechanism similar to that it understands NICOR Gas to have in place with modification to fit within its Gas Rider 2.

3. Staff

Staff informs that it has some concerns with the merits of the pending proposal. It further explains that, because the issues only surfaced on brief, Staff and other parties had no opportunity to offer testimony in the matter. Staff believes that arguments at hand are inadequate for full consideration of the issue.

4. Commission Analysis and Conclusion

The Commission believes that the instant proposals are not properly supported on the record by either testimony or analysis. Nor can we assume that that these proposals are undisputed. Indeed, Staff tells us that it has some concerns. And, we have not heard from all interested parties on the issues. The Commission will not presume acquiescence by silence in these premises. Even if we were to do so, it is clear and obvious that an appropriate record does not exist. As such, the Commission has neither the evidence nor the arguments necessary to arrive at a full and reasonable determination. This is particularly so when the proposal is such that it would upset the rulings we made in a prior order, i.e., Docket No. 01-0707.

Nothing we say here reflects on the merits of the respective proposals. In the final analysis, we agree with Staff that Vanguard, RGS and IIEC are free to bring these proposals in a future proceeding and in manner that will allow for full litigation of the issues by all interested parties.

VI. WEATHER NORMALIZATION – AVERAGING PERIOD

A. Parties' Positions and Applicable Law

To set rates for a gas utility, the Commission must determine (*via* estimate, for future years) the number of "heating degree days" ("HDDs") during which those rates will likely be collected annually. An HDD is not a calendar day. Rather, it is a unit of time in which ambient weather will likely cause customers to consume gas for heating.[24] The colder the weather in a year's span, the more HDDs will accumulate in that year. The more HDDs accumulate, the more therms the utility will deliver and the more revenue the utility will collect. Thus, the Commission uses an HDD estimate to calculate the amount the utility should be permitted to charge per unit of consumed gas, so that the utility will be likely to collect its allowed return (insofar is that return is collected through volumetric charges). If HDDs (cold weather units) are overestimated in rate-making, the utility's volumetric rates will be too low and the utility may under-earn. If HDDs are underestimated, those rates will be too high, potentially causing over-earning.

A central principle for estimating HDDs is weather normalization. The objective is to determine the level of heating degree days in a typical or "normal" year in which the rates will apply. The Utilities propose that two contentious principles be included in the weather normalization process in these proceedings: 1) that the climate of northern Illinois is warming, with the likely consequence that a normal year will contain fewer HDDs in the future than in the past; and 2) that ten years (averaged) of recent weather history will be more representative of future normal weather than will thirty years (averaged) of recent weather history.[25] The AG and City-CUB challenge the inferences that the Utilities draw from the former proposition, and they disagree with the latter proposition.

With respect to northern Illinois' climate, the Utilities' climate science witness, Dr. Takle, describes a scientific consensus that warming is occurring. Consequently, the Utilities maintain, normal climate in the near future will be more accurately projected by data from a shorter (i.e., ten year) recent time frame than a longer (i.e., thirty year) frame "which has many years of data from the less relevant colder regime." NS-PGL Init. Br. at 106. However, both the AG and City-CUB emphasize Dr. Takle's acknowledgement, at Tr. 850, that a general warming trend does not preclude recurrence of colder winter weather. *E.g.*, AG Init. Br. at 22. Indeed, these intervenors

[24] Technically, the number of HDDs is the number of degrees Fahrenheit that actual mean daily temperature is below 65 degrees Fahrenheit. NS-PGL Ex. EST-1.0 at 7.

[25] In either case, weather statistics would be derived from the weather station at Chicago's O'Hare Airport.

note, in February 2007, Chicago experienced its coldest weather in 112 years. Id. at 22.

Regarding their proposed use of a recent ten year (rather than a thirty year) period of weather data for weather normalization (specifically, the ten years from 1997 through 2006), the Utilities cite the most recent Nicor Gas rate case[26], in which we approved the use of a ten-year average of HDDs for the Nicor Gas service territory directly adjacent to the Utilities' territories. Additionally (and independently of our decision in Nicor) the Utilities argue that the evidence in this docket proves that "compared to using an average of the past thirty years, an average of the past ten years will more accurately predict the [HDDs] over the next several years." NS-PGL Init. Br. at 105. The Utilities rely on the analysis of their witness, Mr. Marozas, who concluded, "using all available data since the O'Hare weather station began collecting statistics…that using a rolling ten-year average produces less error than a thirty-year average in predicting the next year out, as well as year two, three, four, and five." Id. at 107. The Utilities' preferred ten year average of HDDs, from 1997 through 2006, is 6044 per year. NS-PGL Ex. BMM-1.0 at 7, Table 2. The corresponding thirty year average (i.e., through 2006) is 6401 HDDs. NS-PGL Ex. EST-1.0 at 28.

The AG counters that the appropriate task here is to discern normal climate, not to predict weather, and that "30-year data does a better job of describing a climate." AG Init. Br. at 21. Therefore, the AG maintains, "most jurisdictions around the country" use a thirty year average of HDDs obtained from the federal National Oceanic and Atmospheric Administration ("NOAA"). However, Dr. Takle opines that the NOAA long-term thirty-year average is a particularly poor predictor, citing a climatological study supporting this opinion. NS-PGL Ex. EST-2.0 at 5-6.

City-CUB assert that the Utilities' proposed ten year weather data sample is simply too short to accurately reflect the relevant climate without statistical distortion. Moreover, City-CUB note, the particular ten year period (1997-2006) the Utilities have chosen in this instance conveniently avoids two years of especially harsh weather (1996 and 2007).

Furthermore, City-CUB contend, even if a period shorter than thirty years were appropriate for the normalization process, the Utilities' own analysis shows that their chosen ten year interval is far from the most accurate predictor of future weather conditions. Citing PGL Ex. BMM-1.0, Fig. 1, City-CUB emphasize that 8-, 11- and 12-year data periods predicted subsequent weather more accurately. Both Chicago and the AG point to PGL witness Marozas's testimony that a ten year interval was selected, in part, for "rounding purposes." AG Init. Br. at 23.

With respect to our approval of a ten year normalization interval in Nicor (Docket No. 04-0779 (Sept. 20, 2005)), both the AG and Chicago highlight the following language in our Order: "No analysis of HDD data has been provided to indicate that the ten-year period proposed by Nicor should not be used." Nicor, at 57. Therefore, the intervenors contend, Nicor is distinguishable from the present case, in which they have analyzed and criticized, with record evidence, the accuracy of the Utilities' ten year

[26] Nicor, Docket No. 04-0779, Order at 57 (Sept. 20, 2005).

weather normalization. The AG adds the more general principle that Commission decisions are not *res judicata*, allowing us to treat each case on its individual facts. AG Init. Br. at 27. City-CUB invoke the corresponding principle that deviation from prior Commission practice, without sufficient record evidence, would be arbitrary and capricious. City-CUB apparently believe that the practice of using thirty years of data remains intact after Nicor.

Also, both City-CUB and the AG question the necessity in these particular proceedings for any deviation from the pre-Nicor practice of using thirty years of weather data, given that the Utilities have earned their allowed return in almost all the years since their previous rate case.

In lieu of the Utilities' proposed ten year HDD data, the AG recommends "[u]se of the most recent 30-year average of HDDs." AG Init. Br. at 28. City-CUB recommends that the Commission utilize either the most recent thirty year period (presumably, 1978-2007) or NOAA's thirty year data (derived from 1971-2000).

Alternatively, City-CUB suggest, if the Commission's confidence in thirty year normalization has waned, that we open a proceeding to develop a single, balanced HDD projection methodology that will be consistently employed in Illinois ratemaking. City-CUB and the AG warn that adoption of the Utilities' ten year normalization in this case will simply encourage other gas utilities to propose unique HDD data periods. AG Init. Br. at 24. The likely outcome, as these parties see it, would be inconsistent HDD forecasts for utilities within the same climate region. The Commission notes, however, that inconsistency in HDD forecasts is inevitable unless utilities use the same data source (such as NOAA), the same number of years and the same starting and ending years in their respective forecasts. If utilities initiate their rate cases in different years, they are unlikely to use the same starting and ending years for their forecasts, even if they use the same total number of years (whether ten, thirty or some other)[27]. Thus, to avoid inconsistency, the Commission would have to establish a standard HDD input for all gas utilities, either statewide or within separate climate regions.

B. Commission Conclusion

Our overarching objective is to set rates with the greatest likelihood of generating the Utilities' allowed annual revenues. To achieve that objective, we have endeavored - due to the correlation between cold weather and gas consumption - to include in prospective rates a factor that numerically represents the ambient conditions typically experienced in northern Illinois. Although we have described such conditions as "normal" (and refer to this process as weather "normalization"), the term can be misleading. Any ambient condition is "normal" if it has, in fact, occurred within a climatic area. But for ratemaking purposes, our target has been those conditions (initially quantified in degrees Fahrenheit, then re-quantified in HDDs) that have *most typically* occurred within the climatic area over any year's time, which we have believed would

[27] For example, Nicor's 10-year data yielded an annual HDD average of 5830, and its thirty year average was 6072 HDDs. Nicor at 53. The Utilities, also using ten year and thirty year data sets here, generated 6044-HDD and 6401-HDD averages, respectively.

most likely occur in subsequent years. We have traditionally used an average for this purpose. That average has been derived (until Nicor) from all the ambient conditions that have occurred within a selected period of thirty preceding years. Thus, we have neither tried to predict weather (what *will* happen in the next several years) nor, as City-CUB state, capture the full range of weather regularly experienced in northern Illinois, except insofar as a "full range"[28] of weather contributes to the calculation of past average weather (which has been our proxy for the most likely ambient conditions, with which rates are calculated). Rather, we have taken an average from the past and assumed that it would recur, over time, in the future.

As the Commission views it, the Utilities are proposing a different, and *predictive,* approach. Rather than quantifying the HDDs that are most likely to arise annually in northern Illinois, the Utilities attempt to identify the period of preceding years that, when averaged, has the highest *predictive* accuracy with respect to subsequent years. Although the Utilities, in response to intervenor criticism, have tried to avoid that characterization, e.g., NS-PGL Rep. Br. at 80, they need not have done so. As Nicor demonstrates, we are no longer mechanically resorting to thirty years of data to accomplish our ratemaking objectives through averaging. The critical question is whether the Utilities' proposed predictive methodology is (at the least) no less likely than our traditional thirty year average to match allowed revenues to actual revenues.

Utility witness Marozas establishes that periods of 8, 12, 11 and 10 years of weather data have (in descending order) greater *predictive* accuracy than do thirty years of data, and that those four data sets are more predictively accurate than any other period between one and thirty years (including both the most recent thirty years (through 2006) and the 30 years ending in the year 2000, used by NOAA). NS-PGL Ex. BMM-3.0 at 4. He also demonstrates that ten years of data are more accurate than thirty years when predicting weather within each of the five subsequent years. Id. Utility witness Takle puts those predictive results in the context of global warming and the upward trend of temperatures in northern Illinois, concluding that the last ten years of weather data are more representative of the region's climatic conditions than the last thirty years of data. This presumably explains why shorter data sets have shown greater predictive accuracy than thirty year sets in the recent years studied by the parties here.

Based on the foregoing evidence, the Commission is willing to approve the Utilities' predictive approach for setting rates in these dockets. While our traditional "most likely ambient conditions" formula, based on thirty years of data, has not prevented the Utilities from earning their allowed return in most years, that does not mean that it was ever an optimal mechanism, or that it remains so today. To the contrary, the Utilities' evidence suggests that it was sub-optimal, and getting more so in an incrementally warming climate. *E.g*., NS-PGL Ex. BMM-1.0 at 4. Thus, while we would have expected thirty year data (based on the general statistical principle that more data regarding varying conditions is better than less) to identify the ambient

[28] Neither the record here nor our previous Orders address whether thirty years necessarily encompass the "full range" of northern Illinois weather. What is known is that the National Weather Service uses thirty years, ending in the most recently completed decade, for normalization. NS-PGL Ex. EST-1.0 at 28.

conditions most likely to occur, record evidence does not show that such conditions, in fact, occurred with sufficient frequency to adhere to past methodology. It should be kept in mind that we are asking weather data to do something they were not gathered for - to match actual future revenue to allowed future revenue, over an indeterminate period of years. In Nicor and in the present cases, we have been prodded to improve this process. The Utilities' predictive scheme appears to be an improvement and we will adopt it and subject it to the test of time.

The Commission does not agree, however, that the Utilities' ten year data set is the optimal choice for rate-setting. The Utilities' reasons for selecting that time frame ("rounding" and consistency with Nicor) do not make up for the greater predictive accuracy apparently associated with 8-, 12- and 11-year data sets. NS-PGL Ex. EST-1.0 at 32. Such "rounding" actually decreased predictive accuracy in this instance, by ignoring those superior data sets. Consistency with Nicor is not our principal objective at this point, since that case began, rather than ended, our movement away from reliance on thirty year data sets for ratemaking. As we noted in that proceeding, "Nicor did not study averaging periods other than ten years or thirty years to evaluate whether another period was even more appropriate." Nicor, at 53. Here, the Utilities demonstrated that other periods are "even more appropriate."

Consequently, we will choose between the two most accurate data sets (eight and twelve years). Utility witness Takle asserts that his own "regional climate model projects a trend in temperature since the mid-1990s that produces a trend in annual HDD totals which is very close to the trend calculated from recorded temperatures at O'Hare." NS-PGL Ex. EST-1.0 at 32. That tips the scale toward the twelve year interval, by aligning the predictive accuracy of that interval with Dr. Takle's perception of actual weather behavior at O'Hare over approximately twelve years. Moreover, while the Commission cannot know how long the rates established here will remain in effect, we do know that the Utilities' current rates have prevailed for twelve years. Therefore, the Commission approves weather normalization based on twelve years of data, which should determine the Utilities' HDD calculations incorporated in the rates resulting from these proceedings.

Additionally, we will require the Utilities to use the most recent twelve years, including 2007, to calculate HDDs for ratemaking purposes here. The Utilities have demonstrated that northern Illinois' climate is trending incrementally warmer. Consequently, the most relevant twelve year data will presumably be the most recent.

The Commission appreciates the concern of Staff, City-Cub and the AG that, without a standardized weather normalization period, utilities in future rate proceedings will offer customized HDD predictions, based on whatever data set produces the most revenue-friendly result. However, when we moved away from automatic reliance on thirty years of data in Nicor, our intention was to develop a better method for synchronizing allowed and actual revenues. Today, we continue that development, based on additional evidence. In subsequent rate cases, we will expect utilities to employ the principles and methods approved here or bear the burden of proving that

additional measures will materially enhance the alignment of allowed and actual revenues.

Additionally, we note that our treatment of Rider VBA has diminished the importance of this issue.

VII. NEW RIDERS

A. Overview

North Shore and Peoples Gas have proposed five different new "tracker" riders: Riders VBA; WNA (as an alternative to VBA); ICR (Peoples Gas only); EEP; and, UBA. Each rider, they explain, presents an automatic adjustment mechanism for some factor affecting the revenues or expenses the Utilities experience. The Utilities further assert that each of the riders meets the traditional tests to be valid and useful riders.

1. Rider VBA

a) North Shore / Peoples Gas

A very large percentage of the Utilities costs are fixed. Even with the Utilities' proposed rate designs, they assert, a significant portion of fixed costs will be recovered through volumetric distribution charges. Rider VBA, the Utilities explain, is a rate mechanism designed to provide the Utilities with a measure of assurance of recovery of the portion of the revenue requirement approved by the Commission in these proceedings that is to be recovered through those volumetric charges. Rider VBA is commonly known as a decoupling mechanism. The purpose of decoupling is to remove both the incentive utilities have to increase sales and the disincentives that utilities have to encourage energy efficiency for their customers. The Utilities have proposed Rider VBA in this proceeding based on their recognition of current environmental and economic realities and the impact of those factors on the regulatory process and the utility business.

The Utilities explain that Rider VBA is a mechanism which will determine an adjustment on a monthly basis for the effects of weather and usage changes, such as those caused by conservation measures, on the Utilities' rates. Rider VBA will be applicable to the Utilities' customers under Service Classification ("S.C.") Nos. 1N, 1H and 2. A separate adjustment would be determined for each applicable service classification.

The Rider VBA adjustment would be computed on a monthly basis by taking the difference between a baseline rate case distribution margin per customer (Rate Case Margin) factor against actual distribution margin (Actual Margin) in a given month. The Rate Case Margin for each month would be based on the Commission approved distribution margin for each month divided by the number of Commission approved customers (Rate Case Customers) for the same month. The difference will be multiplied by the Rate Case Customers and divided by the number of therms estimated for the effective month of the adjustment, yielding the monthly per therm adjustment. The actual adjustment will be computed and applied to customers' bills each month

using actual and rate case data from the second month prior to the effective month of the adjustment to be charged. PGL Ex. VG-1.0 2REV at 47; NS Ex. VG-1.0 3REV at 42-43.

A Base Customer Margin per customer and average number of customers level for each applicable rate classification will be established and a separate adjustment will be computed for each service classification. The monthly adjustments will be established by calculating the difference between the Base Customer Margin and the Actual Margin per customer for the applicable month. That difference will be multiplied by the Rate Case Customers and divided by the number of therms estimated for the effective month of the adjustment, yielding a monthly therm adjustment. Id. at 47 and 43, respectively.

According to the Utilities, Rider VBA would be subject to an annual reconciliation with adjustments to insure that the implementation of Rider VBA is in compliance with tariff provisions and would be filed on the 20th of the month to permit Staff review prior to the effective date of the adjustment. Annual internal audits would be conducted by the Utilities. PGL Ex. VG-1.0 2REV at 48; NS Ex. VG-1.0 3REV at 43; Staff Ex. 1.0 at 28.

b) Staff

Staff opposes Rider VBA on grounds that it violates several legal principles applicable to the development of rates; does not meet the legal burden necessary to warrant special rider treatment; adds additional regulatory overview to an already burdened system; and, unnecessarily supplements the Utilities earnings at the expense of the ratepayers, when the Utilities already have ample opportunity to achieve their authorized rate of return. For these reasons, Staff urges the Commission to reject Rider VBA.

Staff considers Rider VBA to be fundamentally different from any other rider which the Commission has authorized and the courts have upheld. Rather than provide for the recovery of a particular operating expense, Staff notes that Rider VBA seeks to guarantee revenue levels and earnings. According to Staff, Rider VBA takes the revenues that the rates approved in a base rate proceeding were intended to recover (which includes the Company's authorized return on rate base), and provides a surcharge if those rates produced insufficient revenues or a credit if those rates produced surplus revenues. In Staff's view, this is clearly contrary to the rule against retroactive ratemaking. It is well established, Staff argues, that the PUA "prohibits refunds when rates are too high and surcharges when rates are too low." Business & Professional People for the Public Interest v. Illinois Commerce Comm'n., 136 Ill. 2d 192, 209 (1989). Thus, once the Commission has determined a rate to be just and reasonable and put it into effect, it can not later determine the rate was excessive. Business & Professional People for Public Interest v. Illinois Commerce Comm'n., 171 Ill. App. 3d 948, 958 (1st Dist. 1988). Staff maintains that the Commission's authority to adopt formula-based rates does not include the power to provide for retroactive adjustments based on earnings. Illinois Bell Tel. Co. v. Illinois Commerce Comm'n., 203 Ill. App. 3d 424, 436 (2nd Dist. 1990).

Staff's view of Rider VBA is that it seeks to ensure recovery of 100% of the revenue requirement to be recovered through the volumetric component of rates irrespective of any actual reduction in demand. While the volumetric charges are designed to recover some costs that are fixed, these also recover variable costs. According to Ms. Grace, about 5% of Peoples Gas' costs and 1% of North Shore's costs vary with throughput. North Shore Ex. VG-1.0 REV at 6; Peoples Gas Ex. VG-1.0 2REV at 8. While these percentages are not high, Staff asserts that Rider VBA does not produce just and reasonable rates because it provides for recovery of costs that are not incurred if customers reduce demand.

According to Staff, Rider VBA also violates the prohibition against single-issue ratemaking. The rule against single-issue ratemaking, Staff explains, is based on the principle that the Commission sets rates based on aggregate costs and demands. As reasoned by the Supreme Court in Business & Professional People for the Public Interest v. Illinois Commerce Comm'n, 146 Ill. 2d 175, 244-45 (1991), the rule would be violated by consideration of changes in demand without considering changes in expenses, and vice versa.

Here, Staff argues, Rider VBA would adjust rates based on one component of the revenue requirement formula, i.e., revenue based on demand. Case law sustaining the approval of a rider against single-issue ratemaking challenges, Staff asserts, provides no cover to Rider VBA. In upholding the Commission's decision to permit rider recovery of coal tar clean-up costs in Citizens Util. Bd. v. Illinois Commerce Comm'n, 166 Ill. 2d 111 (1995), our Supreme Court held that "[t]he rule [against single-issue ratemaking] does not circumscribe the Commission's ability to approve direct recovery *of unique costs* through a rider when circumstances warrant such treatment." Id. at 137-138 (emphasis added). According to Staff, Rider VBA provides for the recovery of revenue rather than a particular operating expense, and thus does not fit within the exception recognized by the court.

While the Utilities posit that Rider VBA is needed to give them the proper incentives to implement energy efficiency measures, Staff points out that the Commission has not been given the authority under the PUA to adopt incentive based regulation, Illinois Bell Tel. Co. v. Illinois Commerce Comm'n., 203 Ill. App. 3d 424 (2nd Dist. 1990), and adopting a rider to provide for incentive based regulation is improper A. Finkl & Sons Co. v. Illinois Commerce Comm'n., 250 Ill. App. 3d 317 (1st Dist. 1993).

Staff also notes that in 1997, following the decisions in Bell and Finkl, the Illinois legislature passed into law Public Act 90-561, which rewrote Section 9-244 of the PUA to authorize the Commission to implement alternative incentive-based rate regulation in certain well defined circumstances. (See 220 ILCS 5/9-244) Staff notes that the Utilities have not asserted at any time in this proceeding that Rider VBA or Rider WNA are proposed pursuant to Section 9-244, and such riders do not fit within the specific authority provided therein for alternative incentive-based rate regulation. Moreover, Staff maintains that Bell and Finkl hold that the Commission lacks general authority to implement incentive-based regulation and may not rely on the provision of incentives to justify rider recovery continue to apply -- notwithstanding the specific incentive-based alternative rate regulation authorized by the amendment of Section 9-244 -- under the

well established principle of statutory construction that "an amendatory act is to be interpreted as continuing in effect (as previously judicially construed) the unchanged portions thereof." (People v. Laboud, ,122 Ill. 2d 50, 55 (1988); see also Union Electric Co. v. Illinois Commerce Comm'n, 77 Ill. 2d 364, 380 (1979) ("It is well established that the reenactment of a statute which has been judicially construed is in effect an adoption of that construction by the legislature unless a contrary intent appears.")) Staff argues that Section 9-244 provides authority to implement alternative incentive-based rate regulation in specific limited circumstances, but nowhere indicates an intent to establish that the Commission has a general authority to implement incentive-based regulation.

All in all, Staff argues, Illinois courts have held a rider mechanism is effective and appropriate for cost recovery when a utility is faced with unexpected, volatile, and fluctuating expenses. Citizens Util. Bd. v. Illinois Commerce Comm'n., 166 Ill. 2d 111, 138-139 (1995). While the Utilities mention the "unexpected, volatile, and fluctuating" buzzwords in their support of Rider VBA, these are not in the context of an expense since Rider VBA seeks recovery of revenues and the everyday business challenges faced by a utility are not the type of special circumstances that justify rider recovery.

Turning to the record evidence, Staff does not necessarily believe the testimonial claim that the proposed rider will reduce the volatility of ratepayer bills. According to Staff, Rider VBA could actually increase the volatility of bills in that it adjusts margin revenues for an individual month, two months afterwards. PGL Ex. VG-1.0 at 47 and NS Ex. VG-1.0 at 42. For example, Staff notes that the under- or over-collection of margin revenues in December would be adjusted on February bills. If margin revenues in December fall below the target level, then February bills would be adjusted upwards to recover the shortfall. Staff notes, however, that if cold weather in February drives usage and customer bills above average, the February bill increase will be exacerbated by the upward Rider VBA adjustment to recover December's shortfall in margin revenues. In this instance, Staff argues, Rider VBA would exacerbate the upward spike in February customer bills. Staff Ex.8.0 at 12-13.

Staff considers Mr. Feingold's argument that reduced volatility would be accurate if margin revenues each winter are consistently above or below normal. Then, the adjustment process would bring monthly bills closer to the average. In Staff's view, however, a shorter-term variation in margin revenues could increase the volatility of ratepayer bills under Rider VBA as the above example shows. Id. at 13.

According to Staff, the Utilities have proposed other measures that Rider VBA does not take into account, which will also profoundly impact customer bills. At the outset, Staff notes, the Utilities propose to change from a 30-year to a 10-year weather normalization period. PGL Ex. LTB-1.0 at 10; NS Ex. LTB-1.0 at 14. This proposal, which Staff does not contest, should address the Utilities' concern that the decrease in gas delivered and sold to customers is in part due to a warming trend in weather. PGL Ex. RAF-1.0 at 17-19. Further, is the proposal to increase the levels of fixed, customer charges collected from ratepayers. If granted, Staff believes that increases in these charges would reduce the level of revenues recovered by variable charges and thereby stabilize the Utilities' revenue stream. And in Staff's view, both proposals, if accepted, will cause a reduction in revenue variability that undermines the Utilities' justification for

an extraordinary measure, such as Rider VBA, to also stabilize revenues. Staff Ex. 8.0 at 13.

As to the argument that Rider VBA will restore incentive for Peoples Gas and North Shore to promote energy conservation and efficiency programs Staff does not agree. Usage data for the last 12 years indicates to Staff that ratepayers have already taken extraordinary steps to reduce their consumption. Utilities' witness Borgard documents a steep decline in natural gas throughput on the Peoples Gas system over recent years. He notes that throughput on the Peoples Gas system fell from the 1996 level of 235.7 Bcf projected in the Company's 1995 rate case down to a 2006 normalized level of 177.6 Bcf. According to Mr. Borgard, this represents a reduction of 58 Bcf or 25% over the 10-year period. PGL Ex. LTB-1.0 at 10. Mr. Borgard indicated that average annual use by residential heating customers declined by 29% from 160 to 113 dekatherms over the last decade (PGL Ex. LTB-1.0 at 16) and small residential heating customer use for North Shore declined by 16% from 159 to 133 dekatherms over the same 10-year period. NS Ex. LTB-1.0 at 14-15.

Staff also maintains that Mr. Feingold's reference to the "authorized level of margin revenues" for the Utilities is irrelevant in the current regulatory environment. According to Staff, margin revenue has no meaning as a standard for assessing the financial performance of Peoples Gas and North Shore in the Illinois regulatory process. The better and broader measure employed by the Commission concerns the rate of return achieved by the Utilities on their investments.

In Staff's view, simply because NARUC has acknowledged the function of revenue decoupling mechanisms does not translate into support for the adoption of these mechanisms by all state regulatory commissions. Indeed, as Mr. Feingold's own testimony states, NARUC's position is to encourage State Commissions "to review the rate designs they have previously approved to determine whether they should be reconsidered." Id. at 28 and NS at 25. Even if NARUC were to declare its support of revenue decoupling, Staff maintains that this would not mandate the Commission to act. Staff Ex.8.0 at 19-20. Further, Staff does not consider approval by regulators in ten states to demonstrate overwhelming regulatory support for revenue decoupling. Mr. Feingold's numbers would indicate that four out of five regulatory bodies have failed to adopt revenue decoupling. Staff Ex. 8.0 at 20. And, Staff notes too that, among the states that have approved such mechanisms, several have only approved pilot programs, or limited and modified revenue-decoupling programs. Several other states are acting under statutory direction to investigate revenue-decoupling mechanisms as an alternative to traditional statutorily approved ratemaking.

States that have approved decoupling mechanisms have done so with great apprehension, Staff points out, after thorough investigation and testing, and often at the behest of the legislature. These states have adopted revenue decoupling mechanisms, but either as pilot program, with safeguards, or both. In contrast, the instant Rider VBA does not have, nor have the Utilities proposed, any safeguards to protect the ratepayers. The instant Rider also does not allow the Commission to review the effectiveness of the Rider before the Utilities choose to file for another rate case, and there is no expiration or test period to evaluate the effects of Rider VBA.

In Staff's view too, Rider VBA is being proposed to address a problem that does not exist. The financial distress the Utilities claim has simply not been established. The available evidence indicates that Peoples Gas and North Shore have achieved sustained success in recent years despite the business challenges. For example, as Company witness Feingold acknowledges, the cost of service consists of two components, expenses and a rate of return on rate base. Tr.1350. Therefore, if after paying its expenses, the utility realizes its approved rate of return, then the utility is, by definition, recovering its cost of service. According to Staff, Peoples Gas and North Shore have consistently met or exceeded their approved rates of return and recovered the cost of service for a full decade after their last rate case in 1995.

Staff maintains that proposed Rider VBA suffers from numerous deficiencies and asks that it be rejected by the Commission in this proceeding. In the event that the Commission were to determine it appropriate for the Utilities to adjust base rates on a monthly basis for fluctuations in actual revenues, Staff recommends the Commission adopt the language changes which are reflected in legislative style in Attachment C, Staff Revised VBA, to Staff Exhibit 1.0.

The changes are: 1) to reflect an annual reconciliation with possible adjustments to ensure the VBA is in compliance with the tariff; 2) to change the monthly filing date to allow for Staff review prior to the effective date; and 3) to require the Utilities to perform annual internal audits on compliance of the UBA. Staff points out that the Utilities stated no opposition to these proposals, other than one change in the definition of RA. NS-PGL Ex. VG-2.0 at 50. And Staff had no opposition to the Utilities rebuttal changes. Staff Exhibit 13.0 at 15.

c) City - CUB

In assessing Rider VBA, City-CUB point out, the Commission must first determine whether the costs at issue meet the criteria for rider recovery. Only then, they argue, is it able to decide whether or not to exercise its discretionary authority to permit rider recovery. Here, City-CUB assert, the Utilities cannot claim that Rider VBA is designed to recover a volatile, fluctuating cost that is beyond their control. This is so, they argue, because Rider VBA is designed to protect utility revenues and earnings and not to recover a particular cost. And, because the rider at hand would adjust utility revenues outside of a rate case by, in effect, increasing rates when revenues are too low and decreasing rates when revenues are too high, City-CUB maintain that Rider VBA would violate the rule against retroactive ratemaking. Business & Professional People for the Pub. Interest v. Illinois Commerce Comm'n., 136 Ill. 2d 192, 209 (1989) ("*BPI I*").

City-CUB observe nothing in the record to show that the Utilities' respective revenues have been volatile and fluctuating. Their witness Brosch included in his rebuttal testimony two tables showing the margin revenues for Peoples Gas and North Shore from 1996 through 2006. GCI Ex. 4.0 at 6, 7. The table relating to Peoples Gas's margin revenues (Table 6) shows that PGL's margin revenues have hovered around $400,000,000 per year for Peoples Gas over the entire 11-year period exhibited. Id. at 6. North Shore's margin revenues, as demonstrated in Table 7, have stayed around the $60,000,000 level for the same period. Even if one could lawfully protect

utility revenues and earnings through use of a rider, City-CUB maintain that the evidence indicates the Utilities' respective revenues have not been volatile or fluctuating, as Illinois case law requires for rider recovery of specific costs. Thus, City-CUB argue, approving Rider VBA would violate the rule against single-issue ratemaking.

City-CUB also observe the Utilities to claim that Rider VBA should be approved because it does not shift any risk to ratepayers. *See* PGL-NS Init. Br. at 116. The evidence in the case, City-CUB argue, well contradicts that point. Staff witness Lazare's testimony, they note, references the Utilities' answer to an AG data request asking what revenue changes would have been experienced in the past five years if Rider VBA had been in place. The results indicated therein show that Rider VBA would have been a boon to the Utilities. Staff Ex. 8.0 at 7. These numbers, City-CUB note, total to an additional $218 million in pre-tax operating income for Peoples Gas and an additional $24 million in pre-tax operating income for North Shore. GCI Ex. 1.0 at 37. According to Mr. Brosch testimony, and based on the Utilities' analysis of the rider's impact had Rider VBA been in effect for the past five years, Peoples Gas's margin revenues would have increased by about 11.2% and North Shore's margin revenues would have increased by 8.9%. Id. at 37. Contrary to the Utilities' claim, City-CUB argue, these results suggest that considerable risk would be shifted to customers if Rider VBA were approved.

d) The AG

The AG also opposes Rider VBA and on several grounds. At the start, the AG points out that the *Finkl* Court held that rider recovery constitutes extraordinary regulatory treatment that should be used only when evidence exists to show that traditional ratemaking will not effectively reflect the costs in rates. In order to qualify for rider recovery, the AG observes, such expenses must be unexpected, volatile or fluctuating and significant in nature.

GCI witness Brosch testified that while the proposed Rider VBA can be expected to produce relatively large cumulative revenue impacts if it remains in place for many years between rate cases, the change in revenues in individual years is not particularly large. According to the analysis provided by the Company, which detailed the revenue effects if Rider VBA had been in place beginning in 2002, the largest annual margin dollar change was $21.7 million for PGL and $4.5 million for North Shore in 2003. GCI Ex. MLB-1.0 at 39-40. These amounts, after reduction to account for income and revenue taxes of about 40 percent, are significant in the AG's view, but not particularly large in relation to the total test year operating income proposed by PGL of $108 million at proposed rate levels and $16.9 million for North Shore at proposed rate levels. Id. at 40. On this criterion alone, the AG asserts, rider treatment is not justified.

In terms of the volatility criterion, the AG notes, Rider VBA fails the test. It was demonstrated in Brosch's testimony that the actual recorded PGL annual margin revenues have been stable in overall terms for the past 11 years, and fluctuations due to weather and other causes were within or less than 8 percent of the average amount. *See* GCI Ex. 1.0 at 32, 33; GCI Ex. 4.0 at 6, 7. Similarly, for North Shore, relative margin revenue stability is evident across the 1996 through 2006 time period, indicating

no apparent financial need for Rider VBA tracking of usage per customer. GCI Ex. 4.0 at 33. Mr. Brosch also pointed out that the magnitude of changes in annual VBA adjustment amounts, as shown in GCI Ex. MLB-1.3, does not effectively eliminate margin fluctuations during the years modeled. *See* GCI Ex. MLB-1.3 and GCI Ex. MLB-1.0 at 38, 39; Tables 4 and 5.

As such, the AG argues, the usage or revenue per customer decline that Rider VBA is intended to address does not satisfy the "unexpected" criterion referenced in the Finkl case. As both Mr. Feingold and Mr. Borgard have acknowledged, declining use per customer has been a phenomenon occurring for decades. Tr. 378; 1321-1322. Despite this phenomenon, the Utilities have not sought rate relief since 1995 and thus, were able to react to this observable trend through productivity improvement, customer growth, expense reductions and a decrease in the Utilities overall cost of capital. *See, e.g.*, PGL Ex. LTB-1.0 at 13-15. According to the AG, nothing of record suggests that declines in usage per customer, and thereby revenues per customer, will produce unacceptable financial outcomes if the Utilities are not allowed special rider treatment.

The AG points to GCI witness Brosch's testimony which observes that the Rider VBA proposal ignores the traditional ratemaking process, which employs a balanced review of jurisdictional expenses, rate base investment, the cost of capital and revenues at present rates during the test year. If enacted, the AG argues, Rider VBA would violate the Act's prohibition against single-issue ratemaking by imposing a surcharge each month on customers' bills if overall usage in three rate classes dipped below the aforementioned baseline level set in this case, without examining whether *overall* revenues have increased. *See* PGL Ex. RAF 1.0 at 32. Similarly, it would impose a surcharge even if an observable cost reduction in a certain expense category was available to offset any future decline in revenues per customer.

The AG contends that traditional rate of return regulation has worked well for both the Utilities and consumers. Further, the AG notes, rates for Peoples and North Shore will be recalibrated at the conclusion of this docket based on record evidence regarding their respective revenue requirements. If the declining usage per customer trend that has existed since the 1980s affects the Utilities' earnings in the future to a point that rate relief is deemed necessary, the AG observes that the Utilities are free to file a rate case.

The AG notes that the Finkl case specifically rejected the notion of requiring ratepayers to reimburse a utility for revenues lost due to energy efficiency and conservation measures. In Finkl, the AG explains, the Rider 22 at issue would have authorized Edison to charge ratepayers for lost revenues associated with demand-side management activities, similar to the Utilities' request in this docket to adjust rates each month when margin revenues fall below a revenue per customer baseline established in this Order. The Finkl court noted that the proposed Rider 22 recovery of lost revenues associated with the DSM programs "fails to take into consideration Edison's aggregate costs and revenues, which is also the vice inherent in this revenue recapture." Finkl at 328. And, the Court flatly rejected the notion of making a utility whole for lost revenues associated with conservation or DSM programs. Given the ***Finkl*** court's specific rejection of ratepayers compensating a utility for lost revenues arising from energy

efficiency and other measures, the AG argues that the Commission should reject the Rider VBA proposal.

Given the absence of specific statutory authority authorizing the adjustment of customer rates, both on a monthly, piecemeal basis and in the proposed annual reconciliation of Rider VBA revenues, as well as the rule prohibiting retroactive ratemaking, the AG believes it clear that the Commission lacks the authority to approve Rider VBA.

In addition, the AG contends that proposed Rider VBA violates the Commission's and Illinois law's test-year principles by selecting only one component of the revenue requirement, in this case a slice of overall revenues (margin revenues per customer in the Rate 1 and 2 classes), then tracking changes in that revenue requirement component and assessing rate adjustments to recognize this change. Such an approach, the AG argues, would distort test year matching by continuously revising utility prices for changes in future usage per customer, even though other elements of the test year revenue requirement calculation are not being systematically updated.

The AG further points out that Section 9-241 of the Act prohibits a utility from establishing or maintaining any unreasonable difference as to rates or other charges between customer classes. 220 ILCS 5/ 9-241. Here, the AG observes that Peoples and North Shore seek to maintain a designated level of revenues per customer on a monthly basis after rates are set in this docket for the Rate 1 residential and Rate 2 commercial classes, but not for the other rate classes served by the Utilities. Nowhere, the AG notes, is there any evidence to show that the weather variability, declining use per customer, or conservation phenomena are at all unique to residential and small commercial customers and should not also be applicable to larger gas consumers. There is no showing, for example, that Large Volume Demand Service customers' usage, and therefore some element of their fixed cost contribution, are not also impacted by the reductions in usage associated with weather and conservation efforts. Nevertheless, the AG notes, Rider VBA and its monthly rate adjustments arising from variations in usage per customer baseline calculation, would not apply to this customer class. As such, the AG argues, Rider VBA constitutes unreasonable discrimination against residential and small commercial customers.

The AG maintains that state and federal regulatory law is not premised on the concept of maintaining a utility's "margin revenues". The seminal federal cases in utility regulation, the AG asserts, make clear that a utility is entitled to the opportunity to earn a reasonable return of, and on, its prudently incurred utility plant. No mention is made of an inherent right to maintain some level of "margin revenues" or "use per customer". GCI witness Brosch also disagreed with the notion that a specific margin revenue should be guaranteed. He expressly noted, the AG points out, that all of the ratemaking input values will change in the future; test year expenses will change, the cost of capital will change and test year rate base values are not expected to remain constant after completing a rate case. GCI Ex. MLB-1.0 at 36. Even if the Utilities could make a case for the need to ensure its margin revenues, the AG observes that proposed Rider VBA can assess a surcharge even if total revenues increase above the level approved in this rate case, if the use *per customer* declines. According to the AG, there is nothing in the

Act or in Illinois case law setting out a utility's right to maintain a specified level of revenues or usage per customer.

Absent from the record too, the AG notes, is any evidence that *overall* margin revenues have dropped precipitously or become unstable in the years since the Utilities' last rate case so as to justify the unorthodox ratemaking treatment that Rider VBA brings. Despite the declines in usage per customer detailed by Messrs. Borgard and Feingold, the AG observes that overall margin revenues for both Utilities have been remarkably stable. As such, the AG argues, there is simply no basis for the extraordinary ratemaking treatment inherent in Rider VBA.

More specifically, the AG notes that the Utilities presented no evidence to show that they will be precluded from earning reasonable returns in the future absent the newly proposed Rider VBA. When asked in discovery to provide projections of future financial performance with or without the riders, the Utilities responded that, "There are none." GCI Ex. 1.0 at 20. As importantly, the AG notes Mr. Borgard to have confirmed that the Utilities *can* continue to provide safe, adequate and reliable service to all customers *without* Rider VBA. Tr. 392.

According to the AG, the argument that a decoupling rider is needed to remove any disincentive the Utilities might have to promote energy efficiency, PGL Ex. RAF-1.0 at 22; NS Ex. RAF-1.0 at 24, should be rejected for several reasons. First, the AG maintains that Peoples' and North Shore's participation in energy efficiency programs to date have been minimal and primarily the result of legal settlement. Outside of an agreement to contribute $5 million to energy efficiency measures arising out of a settlement in the Docket No. 01-0707 Peoples/North Shore PGA case, and a separate agreement in the recent merger settlement to spend a combined Peoples/North Shore maximum of $7.5 million on an energy efficiency program to be administered by a third party governance board[29], neither Company has any history of promoting or designing significant energy efficiency programs for its residential customers. Second, the AG notes that the Utilities' witness Borgard, made clear during cross-examination that there are no plans to grow energy efficiency programs beyond the $7.5 million program being proposed in this docket either with or without Rider VBA. Tr. 390. Third, the AG observes that the program that the Utilities proposed (with the support of the People and the Environmental Law and Policy Center), would be administered by a third-party Governance Board, which would have control over program selection and marketing. While the Utilities would have a representative among the five-person Board, it is fair to say that they would not be in control of marketing or promotional decisions. Finally, the AG suggests that Rider VBA would, in effect, punish Peoples and North Shore customers by raising future per therm charges on a monthly basis when customers conserve and reduce future gas usage and margin revenue-per-customer below the threshold level set in this docket. It would cause customer confusion given the contradictory price signals sent by adjusting per therm charges upward when usage per customer decreases and likely diminish the incentive customers have to lower their

[29] Docket 06-0540, Memorandum of Agreement at 3, 4.

thermostats, invest in more energy efficient appliances and weatherization measures, or even participate in the company-sponsored programs. GCI Ex. 1.0 at 44.

The AG is similarly not impressed with the Utilities' claims on the nationwide trend toward approval of decoupling mechanisms. At the outset, the AG observes that in Mr. Feingold's discussion of states that had approved a decoupling rider, these involved, in each instance, approval *by settlement* between the utility, a PSC staff and intervening parties, with a quid pro quo of specific commitments toward conservation and energy efficiency programs. Tr. 1286, 1288, 1289, 1291-1296; *Compare* PGL Ex. RAF-2.0 45-46, In the Matter of Northwest Natural Gas – Investigation Regarding Possible Continuation of Distribution Margin Normalization Tariff, Order, August 25, 2005. Further, the AG notes that there is wholly absent from Mr. Feingold's testimony any discussion of state commission decisions that had rejected decoupling proposals similar to the Rider VBA proposal in this proceeding. Accordingly, the AG asserts that Mr. Feingold's testimony on the other jurisdictional approvals is of little value.

Considering the Utilities' claim that Chicago-area weather has been and will be warmer than in years past and that historical declines in natural gas usage per residential customer will continue in the future, the AG believes that the approval of Rider VBA will only deliver generally higher prices and a significant shifting of risk for Peoples' and North Shore's customers, with no benefits in return. For example, the AG notes, the Utilities' witnesses to have made clear that no commitment to refrain from filing a rate case in the future will accompany approval of its rider proposals. Tr. 1541. Similarly, the Utilities specifically rejected the notion that their authorized return on equity should be lowered in recognition of this transfer of risk from the Utilities to its customers. PGL-NS Ex. PRM-2.0. In sum, the AG argues, the record evidence supports Commission rejection of the proposal.

The AG contends that still another reason to reject Rider VBA is that riders, in general, add complexity to regulatory processes in a myriad of ways. This concern was testified to by both GCI witness Brosch and Staff witness Lazare and at length. Further, the AG observes that the inherent complexity in the monthly filings and calculations that are being proposed to administer Rider VBA, can be seen in the proposed Rider VBA tariff itself. *See* PGL Ex. VG-1.16; NS Ex. VG-1.15. According to the AG, The cumulative burden that the review of Rider VBA would add to the Commission Staff's and the consumer intervenor parties' respective auditing and advocacy responsibilities is another reason to reject the Company's Rider VBA proposal.

e) North Shore / Peoples Gas' Response

The Utilities note certain parties to have made generalized arguments claiming that the Utilities' actions have no bearing on customer conservation decisions. But, the Utilities maintain that the existence of the "Throughput Incentive" cannot be denied. According to the Utilities, the Throughput Incentive encourages a utility such as Peoples Gas or North Shore to be financially motivated to increase sales of natural gas (relative to historical levels which underlie base rates) and to maximize the "throughput" of natural gas across its utility system.

Under the traditional utility ratemaking structure, Peoples Gas and North Shore point out, a utility is financially motivated to increase its sales levels in a future period above that established in its previous rate case because its rates are designed to recover most fixed costs on a volumetric basis – causing the utility's revenues to increase as its sales increase. Under traditional utility ratemaking, an increase in the recovery of fixed costs will occur (compared to the level approved in the utility's most recently completed rate case) when sales are higher than assumed in the design of the utility's rates. Conversely, a decrease in the recovery of fixed costs will occur when sales are low relative to assumed levels. This situation, the Utilities assert, creates an automatic disincentive for utilities to promote conservation or energy efficiency initiatives because such actions will reduce the utility's revenues and resulting earnings.

The Utilities would compute a monthly adjustment under proposed Rider VBA to offset the revenue impact of increases or decreases in sales. By doing so, they explain, proposed Rider VBA would effectively eliminate the link between sales and earnings. Hence, Rider VBA would encourage the Utilities to be supportive of measures which would promote decreased energy usage, conservation, or other energy efficiency initiatives. Feingold Dir., PGL Ex. RAF-1.0. The only other arguments which have been set out in opposition to Rider VBA are that it departs from "traditional ratemaking" and would introduce a measure of complexity and administrative burden for regulators. Such arguments are meritless, the Utilities argue.

It cannot be disputed, the Utilities assert, that more and more state commissions are approving revenue decoupling mechanisms similar to Rider VBA in recognition that such mechanisms have identifiable benefits for ratepayers and utilities. The state of New York, the Utilities observe, has even seen fit to recommend that all utilities in the state propose decoupling measures to address today's business realities. Re Investigation of Potential Electric Delivery Rate Disincentives Against the Promotion of Energy Efficiency, et al., 256 P.U.R. 4th 477, 2007 WL 1185703 (N.Y.P.S.C. Apr. 20th, 2007) (Docket No. 03-E-0604).

Rider VBA is an opportunity for the Commission to participate in this growing acknowledgement of the need for rate setting bodies to address issues of global warming impacts and energy independence and their impact on energy utilization, conservation and utility financial stability. Rider VBA, the Utilities assert, serves these critical goals by providing them with a measure of financial stability that will enable them to participate enthusiastically in promoting energy conservation and efficiency without the fear of undermining their business interests.

The Utilities point out that decoupling mechanisms, and their rate tracking features have been widely adopted by state regulatory commissions over the past several years. Decoupling mechanisms had been adopted in at least 9 states when the Utilities filed their cases and that number had risen to 11 nearly six months later with 14 additional states considering decoupling in some manner. NS-PGL Ex. RAF-3.0 at 5. Decoupling mechanisms are becoming increasingly more common across the country in response to significant environmental and national interest considerations, as well as the business challenges faced by natural gas utilities. The environmental challenges that Rider VBA would address, the Utilities explain, involve issues of global climate

change and the real need for the nation to become more self sufficient in energy. NS-PGL Init. Br. at 110-111. Exhibit NS-PGL RAF-2.3 shows the increasingly widespread adoption of decoupling mechanisms across the U.S. While no decoupling mechanisms have been adopted in Illinois, the policy challenges and business justification which are the predicate for decoupling mechanisms certainly do exist in this state.

Among these new realities is that utilities can no longer expect that increased sales are a viable business goal in the face of declining use and the rising cost of natural gas. Moreover, current concerns over global warming and dependence on energy imports have prompted utilities and other policy makers to reevaluate existing regulatory models and express support for decoupling. This has resulted in an ever increasing number of utility proposals and regulatory decisions to implement decoupling and similar type rate policies.

The Utilities point to numerous decisions of other state commissions approving decoupling, and urge the Commission here to make a similar decision. While some decoupling mechanisms have not been approved, the Utilities believe that there is movement toward broader approval. Further the Utilities' financial under-performance in the recent past is clearly indicative of acute business challenges that give rise to the need for new ratemaking approaches because traditional ratemaking approaches do not address current business and environmental realities. A utility's financial results and the environmental consequences of certain ratemaking practices cannot be ignored or downplayed simply to preserve the *status quo*.

Furthermore, the Utilities argue, Rider VBA will not entail any shift of risk to customers because it does not guarantee any specific financial performance. To the extent normal weather is assumed over time, Rider VBA's adjustment to reflect weather represents no risk shifting. Similarly, risks attendant to throughput are evened out by the upward and downward adjustments for warmer and colder weather, respectively. There is no adjustment if the Utilities add or lose customers relative to the customer levels established in these proceedings. The adjustment for usage is symmetrical, i.e., both declines and increases are taken into account. NS-PGL Ex. RF-2.0 at 50-51.

On Exceptions the Utilities note that "The Commission is free to make such 'pragmatic adjustments' as it deems appropriate." NS-PGL BOE at 50. The Utilities further note that these adjustments "could include conditions that Rider VBA may only be implemented as a pilot mechanism, or that Rider VBA be subject to a time frame within which it may remain effective or be subject to the Utilities' being required to file a new rate case to justify its continuation beyond a definitive time frame." Id.

f) Commission Analysis and Conclusion

This case presents the Commission with its first introduction to decoupling mechanisms and it is being presented here with proposed Rider VBA. In simplest form, Rider VBA would adjust customer prices under Service Classifications Nos. 1 and 2, and in a way that the Utilities revenues are held constant despite changes in customer consumption. Such changes in consumption are brought about by rising natural gas prices, the call for conservation measures, warming weather trends, the involvement of

the Utilities in gas efficiency programs, and other events. The proposed monthly adjustments under Rider VBA are symmetrical meaning that they are based on both the over-recovery as well as the under-recovery of target revenues. Implementing Rider VBA imposes some additional administrative expenses and, among other things called for by Staff, there would be annual internal audits.

The question raised by Staff and the GCI parties is whether Rider VBA is legal, i.e., whether it is the type of mechanism that the Commission has authority to adopt. We note Staff to assert, that Rider VBA is fundamentally different from any other rider that the Commission has authorized thus far and which the courts have approved. For their part, the GCI contend that there are serious legal obstacles to be considered. Against these claims, we assess, from the very beginning, the scope of our authority in the matter of riders.

1. Rider Authority

In City of Chicago v. Illinois Commerce Comm'n, 13 Ill. 2d 607 (1958) ("City I"), we observe, the Illinois Supreme Court considered the Commission's power to approve an automatic adjustment clause to be filed in a rate schedule. This opinion makes clear that the Commission's authority to approve rate schedules "embraces more than the authority to approve rates fixed in terms of dollars and cents." Id. at 611. It also includes the power to adopt a set formula to recover costs in appropriate circumstances. Id. In sum, our Supreme Court declared that the legislature has vested in the Commission the ratemaking function which includes the making of "pragmatic adjustments." Id. at 618.

Over the years, we find that the Illinois courts have reviewed the rider mechanism in a number of different circumstances. See A. Finkl v. Illinois Commerce Comm'n, 250 Ill. App. 3d 317 (1st. Dist. 1993) ("Finkl") reversing a rider order for recovery of a type of ordinary costs that should have been included in rate base; City of Chicago v. Illinois Commerce Comm'n, 264 Ill. App. 3d 403 (1st Dist. 1993) ("City II") affirming a Commission order that approved with modification, a rider for recovery of marginal cost of providing non-standard service; Central Illinois Light Co. v. Illinois Commerce Comm'n, 255 Ill. App. 3d 876 (3rd Dist. 1993) ("CILCO") finding no abuse of discretion in the Commission's ordering of coal tar remediation cost recovery through a rider mechanism; Citizens Utility Board v. Illinois Commerce Comm'n, 166 Ill. 2d 111 (1995) ("CUB v. ICC"), affirming on that issue against further rider challenges; City of Chicago v. Illinois Commerce Comm'n, 281 Ill. App. 3d 617 (1st Dist. 1996) ("City III"), upholding the Commission's order for rider recovery of the utility's franchise costs; Illinois Power Co. v Illinois Commerce Comm'n, 339 Ill. App. 3d 425 (5th Dist. 2003) recognizing that the Commission sets rates in two ways-by base rates or by an automatic-cost-recovery mechanism.

Throughout, all that was established in City I remains good and sound law. Indeed, we observe, 37 years after it set out the seminal pronouncements in this field, the Illinois Supreme Court highlighted City I to affirm the Commission's discretion in selecting the means by which rates are set and costs are recovered, and the appropriateness of the rider mechanism in certain instances. CUB v. ICC, 166 Ill. 2d 111 (1995). Thus, the whole of the case law settles the question of our authority to

adopt the rider mechanism in proper situations and under circumstances that are lawful and reasonable.

2. The Legal Objections to Rider VBA

Claiming that the instant Rider VBA is outside the Commission's authority, Staff and the GCI maintain that this mechanism violates certain well-established regulatory doctrines. These, they claim, are single issue ratemaking, retroactive ratemaking, and the Commission's own test year rules.

To be sure, both the GCI and Staff also contend that Rider VBA is unlike any other rider that has been considered by any court. But, Staff further acknowledges that, the lack of judicial review on a rate adjustment such as Rider VBA does not mean that it cannot be judged against the standards that our Illinois courts have considered. We agree with this proposition. Continuing with our analysis, we observe that the Illinois courts have defined, discussed and addressed the legal principles at hand, and their application, in a number of different situations.

While Staff and the GCI parties' briefs and exceptions highlight limited aspects of the relevant case law, we find it necessary to take a more thorough approach in analyzing these court opinions and discerning the guidance that they offer in this matter.

a. Single Issue Ratemaking

In the GCI's view, Rider VBA would inappropriately adjust rates on a going-forward basis to ensure a designated level of revenues per customer, without examining whether overall revenues have increased or whether expenses have decreased to offset revenue losses. This, they contend, violates the prohibition against single-issue ratemaking.

We take a studied look at this regulatory principle and its application by the courts. At the outset, we observe that on review of a rate case proceeding in Business and Prof'l People for the Pub. Interest v. Illinois Commerce Comm'n, 146 Ill. 2d 175 (1991) ("BPI"), the Illinois Supreme Court explained that the rule against single-issue ratemaking recognizes that the revenue formula [R(revenue requirement) = C(operating costs) + Ir (invested capital or rate base times rate of return on capital)] is designed to determine the revenue requirement based on the aggregate costs and demand of the utility. Thus, the Court observed, it would be improper to consider changes to components of the revenue requirement in isolation for oftentimes a change in one item of the revenue formula is offset by a corresponding change in another component of the formula. Id. at 244-245.

This pronouncement figured prominently in the opinion of A. Finkl & Sons Co. v. Illinois Commerce Comm'n, 250 Ill. App. 3d 317 (1st Dist. 1993) ("Finkl"), where the court considered a stand-alone Commission order that allowed Commonwealth Edison Company ("Edison") to recover costs associated with demand-side management ("DSM") programs through a rider and outside a rate case proceeding. The court reviewed the elements of the traditional ratemaking process and determined that, in this instance, the expenses incurred with least-cost planning, i.e., are ordinary expenses of the type recoverable through the usual base rate mechanism. Under this view, the court

considered that the Commission had improperly authorized Edison to charge customers for DSM program costs without considering whether other factors offset the need for additional charges in violation of the prohibition against single-issue ratemaking. According to the court, Edison's failure to include such costs "in its request for a rate increase" did not justify single-issue treatment of costs in a rider. Id. at 327.

In CILCO, however, the court found no abuse of discretion where the Commission's order concluded that coal tar mediation costs would be recovered through the rider mechanism. The challenging parties had relied on Finkl to argue that riders, in general, violate the prohibition against single issue and retroactive ratemaking, and the Commission's "test year rules." The court rejected such a broad reading of Finkl and limited its holdings to the particular facts of the case by stating that:

> In Finkl, the First District….found the demand-side management expenses were not of such a nature as to require rider treatment, and could be readily addressed through traditional base rate proceedings. Id. at 885.

In terms of the matter before it, the CILCO court noted that the costs for rider recovery will vary from year to year such that the Commission had authority to authorize a rider as a preferred means of recovery. Id.

The matter was taken for higher review and, in CUB v. ICC, the Illinois Supreme Court boldly announced that the principle of single-issue ratemaking (as set out in BPI) does not apply except in the context of a complete base rate proceeding. 166 Ill. 2d at 138. The Court observed that this was not a situation where the Commission was treating a single expense item within the context of a general rate case. Even more pointedly, the Illinois Supreme Court set out that:

> [A] rider mechanism merely facilitates direct recovery of a particular cost, without direct impact on the utility's rate of return. The prohibition against single-issue ratemaking requires that, in a general base rate proceeding, the Commission must examine all elements of the revenue requirement formula to determine the interaction and overall impact any change will have on the utility's revenue requirement, including its return on investment. The rule does not circumscribe the Commission's ability to approve direct recovery of unique costs through a rider when circumstances warrant such treatment. CUB v. ICC, at 138 (emphasis added).

Further, in City III, the court upheld the Commission's approval of a separate line-item charge that had franchise fees being charged to the residents of the municipalities assessing the fees, while also removing them from base rates for all customers. The court disagreed that the use of a rider for recovery of these costs violated the rule against single-issue ratemaking, and cited favorably to the Illinois Supreme Court's pronouncement that: "The rule (against single-issue ratemaking) does not circumscribe the Commission's ability to approve direct recovery of unique costs through a rider

when circumstances warrant such treatment." Id. The court further observed that, in the situation at hand, the reallocation that the Commission ordered had no impact on Edison's overall revenue requirement. Where the franchise fees were already included in Edison's overall rate structure, the court reasoned that the Commission simply distributed them with no "direct impact on the utility's rate of return." City III, 281 Ill. App. 3d at 629.

Finally, in Archer-Daniels-Midland Co. v. Illinois Commerce Comm'n, 184 Ill. 2d 391 (1998) ("Archer-Daniels"), we observe that the Illinois Supreme Court upheld a Commission order that allowed the recovery of contract restructuring costs as costs of fuel under a UFAC rider. Specifically, the Court held that the lower court erred in finding the rule against single-issue ratemaking to have been violated. The Court reiterated its holding that, this rule does not apply "except in the context of a complete base rate proceeding" such that it "does not apply in relation to the use of a rider mechanism." Id. at 401-402. Given that the proceeding at hand was not a complete base rate proceeding, the Court found that "the rule against single-issue ratemaking has no application." Id.

Analysis:

From the whole of this authority, we believe it clearly established that the prohibition against single issue ratemaking is operable only in the context of a rate case, and during the phase that balances the utility's cost and allowed revenues under the R=C+Ir formula. It is not applicable to a rider that merely facilitates direct recovery of a particular cost without upsetting a utility's revenue requirement.

Consistent with the pronouncements in CUB v. ICC, City III, and Archer-Daniels, the margin revenues which are recovered under Rider VBA do not involve single issue ratemaking because they do not have any impact whatsoever on the Utilities' overall revenue requirements. *See* City III, 281 Ill. App. 3d at 629. Simply put, margin revenues will have been determined as part of the overall revenue requirement in the instant proceeding and the adjustments that occur under Rider VBA will do nothing to change the Utilities' approved revenue requirement. As such, and under the law, Rider VBA does not violate the rule against single issue ratemaking and we reject the arguments of Staff and GCI to the contrary.

b. Prohibition Against Retroactive Ratemaking.

GCI contends that Rider VBA violates the prohibition against retroactive ratemaking by permitting monthly and annual rate adjustments after rates are established in this case. As such, they argue, Rider VBA would adjust future residential (Rate 1) and general service (Rate 2) customer bills on a monthly basis, using comparisons of actual vs. prior rate case data applying formulistic rate changes determined under the rider. For example, they note, the Rider VBA amount to be computed based on October results would be applied to customer bills in December.

In addition, the GCI observe, Rider VBA's tariff provisions require annual true-ups, with any resulting adjustment (positive or negative) added to or deducted from customers' bills during that period. They observe Utilities witness Grace to have testified that, "any difference between actual billed revenues arising from distribution

charges plus the adjustment and approved distribution margin under the rider will be reconciled on an annual basis and amortized over a 10-month period beginning March, with any resulting positive or negative adjustment added to customers' bills during that period." PGL Ex. VG-1.0 at 47; NS Ex. VG-1.0 at 43. Noting that reconciliations are permissible and do not constitute illegal retroactive ratemaking for expenses appropriately recovered under a rider (such as in Purchased Gas Adjustment Clause proceedings or environmental remediation dockets), the GCI argue that reconciliations on both a monthly and annual basis to capture revenue changes are not permitted under the Act or any Illinois case law analyzing rider recovery.

We here examine what the doctrine at hand really holds and what it means for Rider VBA. It is well established, we find, that the prohibition of retroactive ratemaking is derived from the overall scheme of the PUA and the legislative role assumed by the Commission in the ratemaking process that is prospective by nature. Citizens Utilities Co. v. Illinois Commerce Comm'n, 124 Ill. 2d 195, 207 (1988) ("Citizens Utilities"). This means that once the Commission sets rates, the Act does not permit refunds if the established rates are too high. Nor does it allow for surcharges if the rates are too low. Id. Clear from its initial announcement in the opinion of Mandel Brothers, Inc. v. Chicago Tunnel Terminal Co., 2 Ill. 2d 205 (1954) ("Mandel Brothers"), it is the integrity and stability of the ratemaking process that the rule aims to protect. Another important aspect of the rule, is that the PUA forbids a utility to charge rates different than those established by the Commission in its legislative capacity. Id. at 210.

It has evolved that the sanctity and conclusiveness of the ratemaking process also bears upon the Commission itself. This concept was well illustrated in Citizens Utilities where a Commission rate case order included a $4.2 million reduction to rate base on grounds that a higher tax figure had been used to establish the utility's rates in past years. In addressing the challenges to that action, the Illinois Supreme Court observed that the tax benefits at issue originated as expenses the utility previously had been allowed to recover, meaning that:

> Just as there is no recovery of reparations for rates charged under a Commission order later held to be invalid (Mandel Bros.) there can be no retroactive adjustment simply because the Commission has now decided to treat tax benefits differently. Citizens Utilites,124 Ill.2d at 211.

To be sure, the court in Finkl agreed with the argument that Rider 22 violated the prohibition against retroactive ratemaking. 250 Ill. App. 3d at 329. But, we observe, nothing in the Finkl opinion provides an explanation of the court's reasoning. There is only mention that Rider 22 provided for a prudency review of the expenses passed on to customers with the possibility of refunds if the rates were too high. And, the court summarily cited to BPI v. ICC, 136 Ill. 2d 192 (1989), for the proposition that "[o]rdering of refunds when rates are too high, and surcharges when rates are too low, violates the rule against retroactive ratemaking." Id.

We observe that, in CILCO, parties relied on Finkl in arguing that the riders in general violate, among other things, "the prohibition against retroactive ratemaking,"

and the Commission's "test year rules." Here again, the court rejected such a broad reading of Finkl and explained its limitations by stating, in part, that:

> …we read Finkl as holding that the Commission abused its discretion in allowing a rider recovery mechanism under the circumstances because demand-side management costs are not of an unexpected, volatile or fluctuating nature so as to necessitate recovery through a rider. Again, we do not read Finkl as holding that the Commission does not have the authority to allow recovery of costs through riders. Given our view of the Finkl court's holding, we view the opinion's discussion of retroactive ratemaking and test year rules as dicta. 255 Ill. App. 3d at 885 (emphasis added).

The rider challenges continued by the Illinois Supreme Court in CUB v. ICC. At the very outset of its discussion, the Court recognized that riders "often include a reconciliation formula, designed to match recovery with actual costs." CUB v. ICC, at 133 (citing to City of Chicago, 13 Ill. 2d 607, 609 (1958)). While not addressing the retroactive ratemaking argument directly, because it was found to be waived, the Court found nothing unusual with the reconciliation procedure terms for the rider at hand. The Court observed that the reconciliation formula used to determine the amount of the rider charge includes a matching of costs incurred with the revenue realized. Id. at 140. In the end, the Court found the Commission's approval of a rider for the recovery of coal-tar clean-up costs to be within its authority and not against the manifest weight of the evidence. Id.

In United Cities Gas Co. v. Illinois Commerce Comm'n, 163 Ill. 2d 1 (1994), the Illinois Supreme Court considered various challenges to a Commission-ordered refund of certain gas costs that occurred in the context of a PGA reconciliation proceeding. In pertinent part, the Court rejected the utility's argument that the refund order constituted retroactive ratemaking. Id. at 12. First and foremost, the Court noted that the Commission's order was entered in a reconciliation proceeding under Section 9-220 of the PUA, which is an express exception to the general prohibition against retroactive adjustment of rates. Id. at 14-15. Second, and as importantly, the Court held that the Commission's refund order "did not disturb any of its prior orders or disallow charges or benefits it had previously approved, as did the Commission in Citizens Utilities when it ordered a deduction from the base rate of tax benefits it had allowed for 24 prior years." Id. at 15. Indeed, the Court observed that despite certain testimony of record, the Commission did not make adjustments to, or rescind orders entered in earlier proceedings so as to retroactively deny the utility any revenues or benefits it had previously allowed. As such, the Court addressed what the rule against retroactive ratemaking prohibits and concluded that the Commission's order did not constitute retroactive ratemaking. Id. at 18.

Analysis

What is common to the seminal cases setting out the retroactive ratemaking doctrine is that once the Commission sets rates, these will be held as just and reasonable so long as the order fixing the rates remains in effect. And, it is well-settled

that the Commission sets rates in two ways; by base rates and by an automatic adjustment clause, i.e. the rider mechanism.

Upon careful and studied consideration, the Commission concludes that Rider VBA presents no violation of the rule against retroactive ratemaking. Rider VBA does not disturb either this order or any of the Commission's prior orders. Nor does it disallow charges or benefits previously ordered. The adjustments and true-ups under Rider VBA do nothing to alter or de-stabilize the revenue requirement established here. The rates are what they are. Nor does Rider VBA disturb any of the underling revenue formula components and decisions thereon arrived at through the traditional rate-making process in this proceeding. Nor does Rider VBA suggest that the rates are in any way excessive or insufficient. This order establishes the rate that the Utilities are required to charge and pursuant to Rider VBA the Utilities would only receive the margin revenues that the Commission intends to be recovered. It is not the rates, but the computation of these rates that varies.

The only case that directly considers the rule against retroactive rulemaking in the "true" rider situation is CILCO. And, that opinion strictly limits the application of that doctrine by Finkl to the fact particulars in that decision. In short., we observe, CILCO does not embrace it.

Even if we consider Finkl, however, we see no real analysis there on the rule against retroactive ratemaking. The facts to which the court appears to have applied the rule, i.e., a prudency review procedure, is something common to riders. This was well recognized and looked upon favorably by the Illinois Supreme Court in CUB v. ICC, both in its discussion of reconciliations generally, and in its review of the specific reconciliation mechanism that was at hand. Notably too, the court in CUB v. ICC relied, more than once, on its prior pronouncements in City I.

The sound and enduring analysis in City I makes clear that an automatic rate adjustment clause does nothing to change the fixed and prospective nature of rates approved by the Commission. It explains that:

> [An adjustment] clause is nothing more or less than a fixed rule under which future rates to be charged the public are determined. It is simply an addition of a mathematical formula to the filed schedules of the Company under which the rates and charges fluctuate as the wholesale cost of gas to the Company fluctuates. Hence, the resulting rates under the escalator clause are as firmly fixed as if they were stated in terms of money. City I, 13 Ill. 2d at 613.

This simply means that where a rate schedule approved by the Commission contains a mathematical formula for making future changes in the rate schedule, it is not unlawful under the doctrine of retroactive ratemaking. As such, the GCI and Staff have it wrong. The adjustment contemplated under Rider VBA is precisely the type of adjustment mechanism contemplated in City I which stands as good legal authority.

c. Violations of Test Year Rules.

The GCI contend that Rider VBA would adjust Rate 1 and Rate 2 customer rates on a monthly basis using actual and rate case data from the second month prior to the month of the adjustment determined under the rider. They argue that adjusting rates to reflect one element of the test year's revenue requirement calculation without examining the offsetting expense and revenue component violates this Commission's test year rules.

At the outset, we observe that, in Finkl, the court agreed with the argument that, Rider 22 violated the Commission's own test year rule that require it to view the totality of the utility's financial condition. Id. at 330-332. Reasoning that the DSM costs at issue were properly viewed as ordinary "operating expenses," and that Rider 22 did not utilize a test year, the court concluded that, "DSM costs determined outside of a test year cannot be recovered from ratepayers." Id. at 331.

When considering the rider at issue in CILCO, however, the court flatly rejected arguments based upon test year rule violations and that relied on the Finkl opinion. As was the case with respect to Finkl's finding of retroactive ratemaking, the CILCO court treated Finkl's finding of test year rule violations "as dicta." Id. at 885.

We observe that the Illinois Supreme Court ultimately settled the question in CUB v. ICC, when it directly addressed the argument that a rider violates the Commission's own test year rules. At the outset, the court observed that the test year rule set out at 83 Ill. Adm. Code 285.150, is designed to avert a mismatching of revenues and expenses that might permit a utility to inaccurately portray a higher need for rate increases. Id. at 139. The Court looked favorably on the Commission's explanation that it was not attempting to evaluate or adjust all aspects of the utilities' base rates such that the test year filing was not a prerequisite. Id. In the end, the Court resolved that the test year rule seeks to avoid a problem that is simply "not present" when expenses are recovered through a rider. Id. at 140. The Court also upheld the rider.

Analysis

The Commission considers it clear that there are no test year prescriptions that are violated by Rider VBA. To be sure, the rates we establish arise out of nothing less than a traditional general rate case proceeding where the costs and expenses have been submitted in compliance with the Commission's test year rules. As such, the base rates that are approved in this case and which are the basis for the margin revenues to be recovered under Rider VBA have been evaluated in accordance with the appropriate test year prescriptions. Under the authority of CUB v. ICC, and the soundness of its analysis, we reasonably conclude that there is no test year rule violation with respect to Rider VBA

3. Further Considerations.

The arguments of Staff and the GCI continue and suggest that certain other limitations on riders have been developed by the courts. We consider whether Rider VBA satisfies in these instances.

a. Use of Incentives.

Staff believes that the Utilities suggest that Rider VBA is needed to give them the proper incentives to implement conservation and energy efficiency measures. As such, Staff points out that the Commission has not been given the authority under the PUA to adopt incentive based regulation (Illinois Bell Tel. Co. v. Illinois Commerce Comm'n, 203 Ill. App. 3d 424 (2nd Dist. 1990), and further asserts that adopting a rider to provide for incentive based regulation is improper (A. Finkl & Sons Co. v. Illinois Commerce Comm'n, 250 Ill. App. 3d 317 (1st Dist. 1993)). Staff further notes that, in 1997, and following the decisions in Bell and Finkl, the Illinois General Assembly amended Section 9-244 of the PUA to authorize the Commission to implement alternative incentive-based rate regulation. *See* 220 ILCS 5/9-244. Staff observes, however, that the Utilities do not assert that Rider VBA or Rider WNA are proposed pursuant to Section 9-244, and these riders do not fit under the statute

In other respects, Staff maintains that the holding in Finkl, i.e., that the Commission may not rely on the provision of incentives to justify rider recovery, continues to apply despite the specific incentive-based alternative rate regulation authorized by the amendment of Section 9-244.

We note that, in Finkl, the court reviewed a rider that would recover costs associated with demand-side management ("DSM") programs that ComEd was required, by law, to pursue. One of the arguments raised in Finkl was that the Commission improperly approved Rider 22 "as an incentive to perform a legally required act." Id. at 327. The court observed the Commission to have justified its authorization of Rider 22 on grounds that it removed "a barrier to least cost-planning." Id. at 328. There was no reason to give Edison this illegal incentive, the Court found, where the PUA mandated least cost programs and the utility was under an on-going obligation to comply. Id. This was yet another basis on which the court reversed the Commission's approval of Rider 22. Id. at 327-328.

Not all incentives are unlawful, we find. In Archer-Daniels, the Illinois Supreme Court upheld a Commission order allowing the use of the utility's fuel adjustment clause ("FAC") to recover costs of a fuel contract modification. In its discussion, the Court noted the Commission's expressed concern that the use of FACs would discourage prudent purchasing of fuel by removing the "incentive for utilities to bargain" for the lowest procurement prices. Id. at 399. Given the potential for "disincentives" the Court observed the Commission to have required prudent purchasing practices. The Court found that the utility's action in this situation was "precisely" the type of prudent contract monitoring which the Commission sought to encourage. To disallow recovery of the contract change in this case, the Court reasoned, would create the very danger that the Commission wanted to avoid, namely, removing "incentives" for utilities to engage in prudent purchasing practices. Id.

Analysis

In this instance, Rider VBA does not incent the Utilities to perform any type of "legally required act." If anything, it would serve to "disincent" the Utilities from proposing, as has been done here, the implementation of energy efficiency programs. Unlike the situation in Finkl, however, such energy saving measures are not specifically

required under the Act. The Commission recognized this, and our own limitations in this regard, in the Nicor rate case proceeding, i.e., Docket No. 04-0779.

A utility has natural incentives to not be involved in energy efficiency since such activity is far against its self-interest. Thus, this Commission must be mindful, as it was in Archer-Daniels, as to what message it wants to carry and what policy matters it wants to promote. In the process, it must consider not only what is the interest of consumers, but also what this really means for the Utilities.

b. Matters of Fairness.

In their arguments on brief, the GCI raised the question of discrimination in that the Rider VBA mechanism only applies to Rate 1 and Rate 2 customers.

In City II, the court affirmed a Commission order that approved, with modification, Commonwealth Edison Company's ("ComEd") proposed Rider 28 – Local Government Compliance Costs, providing for the recovery of "the marginal costs of providing 'non-standard' service from customers within any governmental unit that mandates such service." Id. at 404. The pertinent issue on review concerned whether Rider 22 creates unlawful rate discrimination. Id. With respect to that claim, the court found that the City failed to submit any evidence before the Commission and failed to meet its burden on appeal. Id. at 411. The court upheld a Commission order approving rider recovery in these circumstances.

We observe that it is Rate 1 and 2 customers who will benefit under energy efficiency measures. It is also these customers that have the best opportunity to conserve. It is also on behalf of these customers that the GCI challenge rate design configurations that would move toward greater cost recovery of fixed costs. The GCI, however, do not mention or analyze any of these matters. It is not discrimination per se, but unreasonable discrimination that must be established. As in the opinion set out above, the GCI have not met their burden here.

c. The Question of Revenues.

Staff and the GCI contend that Finkl specifically rejected the notion of reimbursing a utility for lost revenues due to energy efficiency measures in a rider. As such, they argue that Rider VBA is illegal.

In Finkl, it was argued that the Commission's approval of Rider 22 improperly and illegally authorized Edison to charge ratepayers for lost revenues that, in this context, were "revenues that the utility would have earned but for DSM capability building activities." Id. at 328. This feature of Rider 22, the court observed, failed to "take into consideration Edison's aggregate costs and revenues" and thus, "runs afoul of basic ratemaking principles." The court summarily disposed of the matter by stating that the lost revenue charge here "does not reflect the cost of providing electric service," does not reflect a cost that benefits ratepayers and, further, adds to Edison's revenues without regard to whether Edison's demand or revenues increased because of factors unrelated to DSM programs. Id. at 329.

This was yet another aspect of the court's ultimate and overall determination that costs and revenues are to be determined in a traditional rate case proceeding. To be

sure, the Finkl court was largely focused on the costs of DSM programs that ComEd sought to recover in a rider mechanism. Its criticisms of the rider all were based on doctrines of validity to the ratemaking process and it strongly disapproved of the costs not having been included in the company's last rate case.

There is much to distinguish Rider VBA from the facts at issue in Finkl. In that opinion we see that ComEd was seeking to recover "profit loss" and not margin revenues. Id. at 321. The opinion also mentions testimony to the effect that "demand-side resources provide much lower earnings than supply-side resources." At another point too, the court noted that ComEd had not demonstrated that its DSM efforts "to date" had been hindered by lack of an approved cost recovery mechanism, even though it had engaged in DSM conservation activities "well before" the rider was filed. Further, we note that Finkl is internally inconsistent. At one point. it acknowledges that a utility's least-cost plans are to be, to the fullest extent possible, consistent with the statewide plan (Id. at 320), yet the court did not take into account that the statewide plan, which it also mentions, addresses "the recovery of a particular cost associated with demand-side programs due to lost revenues. Id. at 321.

To date, no court has directly addressed Finkl's disposition of the lost revenue argument. In any event, we note, Rider VBA is far different from the rider challenged in Finkl. Unlike the situation in Finkl, Rider VBA does not seek to recover lost profits. Unlike the situation in Finkl, Rider VBA is not linked to earnings lost due to the energy efficiency programs being proposed (and not legally mandated as were the DSM programs). And, in stark contrast to the situation in Finkl, Rider VBA is being proposed in a traditional rate case proceeding. For all these reasons, we do not consider Finkl to limit our authority to consider Rider VBA.

d. Unexpected, volatile or fluctuating costs

In Finkl, the court recognized that riders are "useful in alleviating the burden imposed upon a utility in meeting unexpected, volatile or fluctuating expenses." 250 Ill. App. 3d at 327. But, it also considered the DSM related expenses at issue, i.e., payroll for planning and similar positions; personnel training, education and travel; contractors and consultants costs; out-of-pocket promotion and computer costs; and conducting workshops., to be ordinary expenses. Id. In the end, the court expressed that these DSM costs "reveal no greater potential for unexpected, volatile or fluctuating expenses which Edison cannot control, than costs incurred in estimating base ratemaking." Id.

Notably, in City III, the court considered the City's reliance on Finkl for the very proposition that only unexpected, volatile or fluctuating expenses are properly recovered through a rider. This opinion (and, notably, by the very same appellate district that decided Finkl) makes clear that:

> A Finkl, however, should not be so narrowly construed. In A. Finkl, we stated that "riders are useful in alleviating the burden imposed upon a utility in meeting unexpected, volatile or fluctuating expenses." (Emphasis omitted.) A. Finkl, 250 Ill. App. 3d at 327, 620 N.E.2d at 1148. Nothing in the language of A. Finkl, or the case upon which we relied,

> Citizens Utility Board, 13 Ill. 2d at 614, 150 N.E.2d at 780, limits the use of a rider only to those cases where expenses are unexpected, volatile, or fluctuating. Id. at 628.

Thus, the City III court construed the opinion of the Illinois Supreme Court to mean that there is no requirement and no limitation on the Commission to use a rider mechanism only for costs that are unexpected, volatile or fluctuating. This brings us back to the pronouncements that riders are allowable in the proper case, and under circumstances that reflect the need for pragmatic adjustments.

4. Whether Rider VBA is appropriate in these circumstances.

In City III, the court reasoned that:

> Matters of rate regulation are of legislative character and courts should not interfere with the functions and authority of the Commission so long as its order demonstrates sound and lawful analysis. Id. at 622 (citations omitted).

We accept that our discretionary authority to approve the rider mechanism in any situation must rest, not simply on our inclination, but on the basis of sound and reasoned judgment.

The sum of our extensive review shows that Rider VBA complies with legal requirements, contains no other infirmity, and falls under our authority. The only question that remains is whether, under all of the facts and circumstances, it is a pragmatic adjustment. Thus, we turn our attention to the entirety of the evidence and arguments of record and to all reasonable inferences that may be drawn therefrom.

The record in this case persuades the Commission that Rider VBA is appropriate as it reflects the particulars of declining and variable customer usage patterns and the concomitant revenue recovery impacts for Peoples Gas and North Shore. In our view, this evidence of usage patterns and margin recovery fluctuations calls for a regulatory response. This, we note, is not a novel idea.

The rate adjustment mechanism upheld in City I, was proposed to reflect the changed business conditions of escalating commodity gas costs relative to other utility expenses recovered in rates. Other, but equally valid business challenges, i.e., fluctuating customer usage and the inability to fully recover authorized margin revenues, have here prompted the Utilities to propose Rider VBA,

We consider the underlying conditions and realities that necessitate the Utilities' proposal. No party can or does dispute the high cost of natural gas. Nor does any party dispute the proposition that high gas prices cause certain customers to conserve. Indeed, Staff makes this point clear in all of its testimony on record. While the benefit of conservation to ratepayers is obvious, we are compelled to recognize that it brings negative consequences to bear on the Utilities. And with warmer than normal conditions, a factor outside the Utilities' control, customers naturally reduce their gas consumption. This too, puts the Utilities at risk for recovering their authorized revenues.

Still, the record includes much more that we need consider. Notably, in this proceeding, the Utilities are proposing an Energy Efficiency Program ("EEP"). They have developed this proposal, not solely on their own terms or under their exclusive control, but with the assistance and participation of ELPC and the GCI parties. This is an unusual effort, being far removed from the Utilities' traditional role and well against its basic interests. At the same time, we must acknowledge, it is a laudatory and socially desirable proposal.

While the GCI parties fully support EEP, they pay no mind to what this means for the Utilities. When dutifully considered, however, the effects of the implementation of energy efficiency programs flow exclusively to the benefit of customers. This means that efficiency strategies and improvements, by their very nature, will worsen the Utilities' ability to recover margin revenues in the immediate future. Furthermore, unlike simple conservation activities, efficiency improvements have more long-term sustained effects. In this regard, the Utilities are correct in arguing that our approval of Rider EEP will exacerbate the problem that Rider VBA is intended to address.

Both the Utilities' embrace of energy efficiency programs, and our recognition of customer gas-saving initiatives, compel the view that these developments need be balanced with appropriate adjustments. In our view, energy efficiency is an underutilized resource. All market participants, including the Utilities need to be part of a concerted effort to change the *status quo*. And, in the process, the current regulatory structure may also have to be re-examined and better tuned to accept new factual realities and policy objectives. We have on record in this case, solid reason to find Rider VBA a proper regulatory response for all of the changing realties reflected in these premises.

If there is a different mechanism to be employed in this situation, it would be a straight-fixed variable (SFV) rate design which recovers all fixed costs through fixed charges. Neither the GCI parties nor Staff, however, advocate for this mechanism. Nor have they expressed to this Commission that it is the preferred alternative. In our view, Rider VBA is a reasonable response because it simply involves the recovery of margin revenues that we have already established in this case. In terms of the mechanism itself, the record shows that Rider VBA is designed with symmetry, transparency, and accountability. In these respects, this rate mechanism works to the benefit of both the Utilities and their customers.

We confirm, on the basis of our legal analysis, that Rider VBA meets the criteria for a lawful rider in Illinois. In its operation, Rider VBA would have two primary functions. First, Rider VBA would increase rates to account for margin revenues which the Utilities would be unable to collect, in a given month, due to changes in customer usage. Second, Rider VBA would lower rates to account for any over-recovery of margin revenues by the Utilities, in a given month, due to customer usage changes. These rate increases and decreases would occur under Rider VBA by operation of a mathematical formula that is applied to the margin revenues that will have already been fixed and approved by the Commission in this proceeding. Thus, Rider VBA involves no more than periodic adjustments to a rate that is fixed and approved by the Commission and with such adjustment as determined by application of a set mathematical formula.

This type of rider formulation is the type of mechanism that the Court endorsed in City I, *i.e.*, a rate schedule that contains "provisions which affect the dollars and cents cost of the product sold." City I, 13 Ill.2d at 611.

In the final analysis, we are simply unable to approve only those measures that benefit ratepayers and wholly ignore what the impacts of these benefits will have on the Utilities. To do so could well be unlawful as this Commission is put to the obligation of balancing both the interests of consumers and the interests of the Utilities. *See* BPI, 146 Ill. 2d 175, 208 (1991) (stating that the Commission is charged with setting rates which are just and reasonable not only to the ratepayers but to the utility and its shareholders). Under the whole of the balancing process, we find it sound and reasonable to approve Rider VBA.

We are surely under no obligation to consider the ratemaking practices employed in other jurisdictions. Nevertheless, we cannot deny that decoupling mechanisms are increasingly coming into use across the nation. While this activity does not bear directly on our decision, and the careful way that we have analyzed the proposal, it does show that new and changing realities are indeed calling for new regulatory responses.

The testimony of Staff sets out certain recommended language changes to Rider VBA. First, Staff recommends an annual reconciliation with possible adjustments to ensure VBA is in compliance with the tariff. Second, Staff proposes to change the monthly filing date to allow for Staff review prior to the effective date. Third, Staff recommends that the Utilities be required to perform annual audits on compliance of the VBA. Staff also informs that while one definitional aspect of its recommendations was disputed, it has been resolved, such that the Utilities agree to accept Staff's recommendations. We further note that, despite the opportunity to do so, no other party has proposed changes to Rider VBA. The Commission finds each of Staff's recommendations laudable given that they provide important safeguards to protect ratepayers, and therefore they are adopted. Furthermore, given the unique nature of Rider VBA, the Commission deems it appropriate to implement VBA as a four year pilot program. The Commission further accepts the Utilities' suggestion that a general rate case needs to be filed if Rider VBA is to become effective upon the conclusion of the pilot program. The Commission is mindful of the concerns expressed by Staff, the AG, and City-CUB. Given that this decoupling mechanism presents a case of first impression for the Commission, we will be ever vigilant in our oversight of the deployment and impact of this new Rider.

In furtherance of Commission oversight of this pilot program, the Commission directs Staff to provide Commissioners an annual report on the Companies' rates of return and the effect on that return of Rider VBA, to the extent that is determinable by Staff. In addition, as provided for under Section 9-250, the Commission may, at its discretion, also initiate a proceeding to evaluate the effectiveness of the Rider. We believe that with these safeguards approval of Rider VBA is supported by record evidence in this proceeding and important forward looking policy considerations.

Finally, Rider VBA should only allow the Utilities to recover its fixed costs attributed to small residential service (Serv. Class. No. 1) and general service (Serv. Class. No. 2), and not its variable costs. To this end, the Commission directs the

Utilities to set the VBA formula to recover only its fixed costs (which is 95% for Peoples Gas and 99% for North Shore (NS VG-1.0 REV at 6; PGL Ex. VG-1.0 2d REV. at 8)) and not to include the variable costs.

Because we approve Rider VBA, the Commission finds no reason to discuss Rider WNA, the alternative proposal put forth by the Utilities.

B. Rider ICR

Approximately half of Peoples Gas' system mains (totaling nearly 2000 miles[30]) are cast iron and ductile iron ("CI/DI"). Peoples Gas has been steadily replacing these mains since 1981 with cathodically protected steel and plastic pipe. Since 1981, the target date for completing the replacement project has been 2050[31]. However, if the Commission approves proposed Rider ICR (Infrastructure Cost Recovery), Peoples Gas would endeavor to accelerate the pace of replacement, so that completion would occur in "the 2025, 2030 time frame." Tr. 1542 (Schott). According to Peoples Gas, Rider ICR will enable it to more readily take advantage of main replacement opportunities as they arise without what the Utilities describe as the negative financial consequences such business actions would create under traditional ratemaking methods. Stating this differently, Peoples Gas would attempt to speed up its main replacement program because Rider ICR would authorize recovery of costs associated with capital investments in CI/DI before they are accounted for in Peoples Gas's base rates in its next rate proceeding. As currently quantified, full replacement of Peoples Gas's CI/DI mains will exceed $1 billion. PGL Ex. JFS-1.0 at 9-10.

Rider ICR would apply to customer classes 1H (residential heating), 2 (general service or small commercial) and 4 (large volume demand). PGL Ex. VG-1.0 at 49. Annual rate adjustments would be determined by the amounts recorded in accounts 376.1 (Distribution Mains), 376.3 (Vaults and Regulators), 380.0 (Services), 380.1 (Meter Purchases), 382.0 (Meter Installations) and 383.0 (House Regulators)[32]. PGL Ex. JFS-1.0 at 4. Amounts included in the calculation of PGL's rate base in this proceeding, and amounts associated with main replacements installed before the end of the test year, would be excluded, as would plant installed for new customers. ALJ Ex 1. With Rider ICR in place, Peoples Gas would optimally double the annual rate of CI/DI main replacement, from the current 30 to 50 miles to 60 to 100 miles, Tr. 1542 & 1551

[30] In 1981, cast iron main represented 86 percent, or 3450 miles out of 4031 miles, of main in Peoples Gas's distribution system. Id. By the end of fiscal year 2006, cast iron main had been reduced to 49%, or 1978 miles out of a total of 4025 miles.

[31] A 2002 study found that this target remained reasonable, prudent and superior to alternatives that added or subtracted 10 years. NS-PGL Ex. ED-1.0 at 14.

[32] As initially proposed, Rider ICR would have involved different calculations. Peoples Gas would have netted the average amount of main replacement investments for fiscal years 2004-2006 against Peoples Gas's actual capital expenditures in these same accounts in a fiscal year. If the latter expenditures exceeded the 2004-2006 baseline, the difference would have been billed through a per-customer monthly charge in the following year. However, Peoples Gas later modified and accepted a version of Staff's alternative Rider QIP, which does not contain the baseline expenditure provisions.

(Schott), although Peoples Gas is not committing to achieve that (or any specific) accelerated replacement rate. Id. at 1617-18.

Over the course of this case, Peoples Gas agreed to modifications of Rider ICR proposed by Staff and Intervenors, but rejected a Staff proposal to include a rate of return credit provision in the rider. Staff also recommended renaming the rider "Rider QIP," to mirror a provision in 83 Ill. Adm. Code 656 ("Part 656") for water and sewer utility infrastructure (authorized by Section 9-220.2 of the Act[33]). The modifications Peoples Gas accepted are: 1) that only the costs of the CI/DI main replacement program will be recovered via the Rider through the application of specific eligibility criteria; 2) creation of a separate revenue sub-account; 3) a cumulative cap of 5% of base rate revenues[34]; and 4) an annual reconciliation of prudently-incurred costs. NS-PGL Ex. JFS-2.0 at 4. With these provisos in place, the Utilities annual recovery (of the pre-tax carrying costs and depreciation associated with ICR-eligible expenditures) would be capped at about $18.5 million (assuming Peoples Gas doubled its replacement mileage and replacement costs with Rider ICR in place). Tr. 1566-68 (Schott).

Peoples Gas contends that accelerating the CI/DI main replacement will produce several significant monetary benefits. First, Peoples Gas avers, shortening the approximate 40-year time frame for completing the main replacement program would decrease overall cost, because more current dollars will be used. Second, replacement of Peoples Gas's low pressure system with medium and high pressure will reduce future repairs and increase efficient operation, thereby reducing maintenance costs. Third, Peoples Gas asserts it will be better able to seize significant cost-reduction opportunities (principally street destruction and repair costs) when the City of Chicago or third-parties pursue development projects which permit coordination of main replacements.

Peoples Gas also claims that various operational benefits will result from main replacement acceleration, including meter relocation, regulator vault replacement and reduction in the occurrence of certain service outages. Inside meters could be moved to building exteriors, avoiding the difficulties and customer inconveniences associated with inside inspections. PGL Ex. JFS-1.0 at 7; Tr. at 1551 (Schott). Meter relocation would also facilitate installation of automatic meter reading devices and enhance meter tampering detection. PGL Ex. JFS-1.0 at 9. Ultimately, Peoples Gas insists, Rider ICR "will not result in additional costs to ratepayers over what would be paid in any event for CI/DI main replacement in the aggregate and PGL will not obtain any financial benefit that is different from the rate case treatment which it is normally accorded for capital expenditures. NS-PGL Ex. JFS-2.0 at 9.

Furthermore, Peoples Gas maintains that it cannot obtain the benefits ostensibly associated with acceleration of the Main Replacement Program without Rider ICR.

[33] 220 ILCS 5/9-220.2.

[34] The cap is not an annual limit. It applies to total recovery under Rider ICR over the entire time it is effective. Tr. 1571 (Schott). The cumulative recovery limit is approximately $123 million under current rates, but would be likely higher (because it is based on actual future revenue) under the rates approved in this Order. Id.

"Only Rider ICR adequately addresses the financial impact of the magnitude and uncertainty that accelerating CI/DI main replacement would entail on an ongoing basis. Only Rider ICR would allow [Peoples Gas] the financial wherewithal to respond to external forces and events and thereby manage the unpredictability and uniqueness of the opportunities which acceleration would afford." NS-PGL Init. Br. at 128-29.

With respect to our authority to approve Rider ICR, Peoples Gas argues that there are no rigid prescriptions for employing riders. It claims that rate trackers have increasingly become a reasonable and useful mechanism employed by utilities and approved by regulators to recover the costs of extraordinary expenses. NS-PGL Ex. RAF-2.0 at 32. Furthermore, Peoples Gas emphasizes, the Commission has implemented riders in numerous instances.

Peoples Gas "strongly opposes" Staff's proposal to include a rate of return credit in Rider ICR. NS-PGL Init. Br. at 132. "Rider ICR was intended to be a straightforward mechanism to provide some rate recovery for the cost of acceleration of the replacement of CI/DI main between rate cases. The credit mechanism could have the effect of eliminating recovery of the costs Rider ICR is designed to recover." Id. Peoples Gas stresses that Rider ICR would recover actual expenditures and that "[i]f the credit operates to limit or reduce the ICR revenue, [Peoples Gas] will be precluded from recovering the costs it would have actually expended." Id.

The City supports Peoples Gas's request for approval of Rider ICR. The City underscores the importance of improved infrastructure within its corporate limits. City ICR Rep. Br. at 3. It characterizes the proposed acceleration of main replacements as a "significant effort" toward infrastructure enhancement. Id.

The AG, Staff and CUB all respond that Peoples Gas has not demonstrated the need for Rider ICR. They maintain that Peoples Gas has satisfactorily conducted main replacement since 1981. *E.g.*, "[T]he Existing Main Replacement Program process has worked well from both a safety and financial perspective for both [Peoples Gas] and its customers, and supports rejection of Rider ICR." AG Init. Br. at 76. The AG attributes this ostensible success, in part, to Peoples Gas's Main Ranking Index ("MRI"), by which Peoples Gas prioritizes main segments for replacement[35], so that potentially problematic segments are addressed first. Id. at 78-79. Under Rider ICR, "mains with an MRI ranking of less than 3.0 - currently not scheduled for replacement due to their superior maintenance history - may be replaced." Id. at 79.

Moreover, the AG argues, Peoples Gas has replaced CI/DI main at a satisfactory pace while reducing employee headcount, investing in new utility plant and earning its allowed return. Under Rider ICR, the Intervenors and Staff complain, Peoples Gas could recover additional revenues associated with the accelerated capital additions costs, even while exceeding its authorized return. AG Init. Br. at 83-84 (*citing* Tr. 1614 (Schott)). Accordingly, the AG questions the need for Rider ICR, which "shifts costs and risks to customers between rate case test years, while removing any management

[35] Per the MRI, compromised main segments are scheduled for replacement, while others are earmarked for possible retirement when work on adjacent segments or other circumstances present a propitious opportunity. NS-PGL Ex. ED-1.0 at 15-17. Others are sufficiently sound to remain unscheduled.

incentive to carefully manage and optimize capital expenditure levels." Id. at 81. For its part, Staff emphasizes that Peoples Gas's main replacement program does "not provide any new or enhanced service" and, therefore, merely imposes "an extraordinary price on ordinary gas service." Staff Init. Br. at 192.

The AG also questions Peoples Gas's claim that the low pressure systems subject to accelerated replacement "are particularly susceptible to outages caused by water seepage." NS-PGL- Init. Br. at 124. The AG states that, whatever the general truth in Peoples Gas's assertion, "no particular problem with outages or main leaks has been identified ...Instead…the record shows that leak repair data compiled over the last 10 years under the existing main replacement program validate that 'there has been a steady decline in the number of leaks per mile of cast iron main…confirming that the Company's program is targeting the correct mains for replacement.'" AG Rep. Br. at 52, *citing* PGL Ex. ED-1.0 at 17.

Additionally, the AG, Staff and CUB underscore that Peoples Gas is not precluded from accelerating its main replacements and, if it so chooses, requesting an appropriate rate increase. These parties dismiss Peoples Gas's contention that awaiting the outcome of a rate case would expose it to financial difficulties, asserting that Peoples Gas has not attempted to quantify its alleged financial detriment. *E.g.*, AG Init. Br. at 83-84; Tr. 1621 (Schott). "[Peoples Gas] has done nothing to demonstrate the magnitude of its alleged financial detriment regarding rate base versus rider recovery of capital costs." Staff Rep. Br. at 74

Staff, CUB and the AG also contend that Peoples Gas has not proven that the benefits of rider recovery for accelerated main replacement are as significant as Peoples Gas alleges, or that such benefits outweigh the corresponding costs. As Staff puts it, Peoples Gas's "benefits argument is premised on the view that a rider is allowable on a simple cost-benefits analysis…[T]hey have not even made that showing." Staff Rep. Br. at 73.

Regarding the CI/DI replacement program, Staff states that Peoples Gas "has not demonstrated any variability in costs. Indeed, the only capital expense cost factor [Peoples Gas] identifies is street repair costs (assuming those costs are capitalized), and there is nothing to indicate the magnitude of those costs or the amount of alleged savings from better opportunities to coordinate." Staff Rep. Br. at 74. Accordingly, the opponents of Rider ICR do not believe that significant construction savings (benefits) will result from acceleration.

Furthermore, insofar as operations and maintenance savings result from main replacement (and arise sooner under an accelerated program), the opponents emphasize that such savings will not be recognized by Rider ICR. Thus, while Peoples Gas projects annual O&M leak repair savings ranging from $180,000 to $300,000 per year[36], (Tr.1549-51 (Schott)), Rider ICR would permit Peoples Gas to retain those savings. Staff Rep. Br. at 73. In a rate case, those savings would be "embedded within

[36] The ostensible savings related to *acceleration* of main replacement is actually half of this amount, which includes the replacement mileage completed *without* acceleration.

recorded test year operations and maintenance amounts" where ratepayers would benefit from them. AG Init. Br. at 83-84. Similarly, the AG maintains that "[u]nder traditional ratemaking, in a base rate case, both increases in plant and decreases in plant are reflected in rates simultaneously." Id. at 86. While Rider ICR would provide recovery on new plant investments without a new rate case, "the offsetting depreciation and retirement of existing plant – on which the utilities are still earning a return – would be ignored." Id.

Commission Conclusion

Many of the governing precedents and principles delineating our discretionary authority were previously discussed in this Order. For the purpose of assessing Rider ICR, we will again review those precedents to identify the governing principles that have been developed for automatic adjustment riders over the past 50 years.

In City of Chicago v. Commerce Commission, 13 Ill.2d 607, 150 N.E.2d 776 (1958) ("City I"), the Illinois Supreme Court addressed "the power of the Commission to authorize an automatic adjustment clause in a utility rate schedule, which it described as "a question…of first impression in this court." 13 Ill.2d at 609-10. Emphasizing the "pragmatic" ratemaking power vested in the Commission by the legislature, id. at 618, the Court concluded that the Act "vested in the Commission the power to authorize an automatic adjustment clause to be filed in a rate schedule in the proper case." Id. at 614. The Court then considered whether continuous recovery of gas costs through an automatic adjustment mechanism constituted a "proper case." It concluded that, "under the facts of this particular case," an automatic fuel adjustment rider was not an abuse of Commission discretion. Id. at 614 & 618.

In reaching that conclusion, the Court underscored several attributes of the fuel adjustment rider under review. First, it resolved that gas costs were not the sort of operating expenses requiring a reasonableness assessment by us, because a federal agency performed that function exclusively. "[T]he Commission is without power to consider the reasonableness of the [Federal Power Commission] rates." Id. at 616. In contrast, the infrastructure capital costs that would pass through Rider ICR here are not operating costs, are not reviewed by any other agency before pass-through to consumers and are invariably, per statutory requirement, evaluated for reasonableness by us.

Second, the Court determined that it could not find "that the public or consumer has lost, nor the Commission abandoned, any rights or powers by the authorization of the automatic adjustment clause." Id. at 618. However, the Court stated, "[i]f the Commission, by authorizing the automatic adjustment clause, had given up its rights to initiate proceedings to determine the reasonableness of Peoples rates until the utility should file a new schedule of rates, we might agree with the city's position [opposing the rider]. However, it has not done so." Id. at 617. The Court stressed that then-Section 41 of the Act empowered us to investigate - at any time - the reasonableness of the utility's rates. Id. In the present case, however, Rider ICR would take away our power

to utilize the successor statute to Section 41 (Section 9-250 of the present Act) to investigate the reasonableness of Rider ICR, for at least three years:

> If the annual reconciliation fled by the Company shows that the revenues collected by application of the ICR surcharge rider exceed actual [qualifying infrastructure plant] costs *for three or more reconciliation years*, the Commission may initiate hearings under Section 9-250 of the Act…to determine whether the rider should be canceled.

ALJ Ex. 1 (Rider ICR) at 11 (emphasis added)[37].

Additionally, the Court determined that an automatic adjustment clause does not shift the burden of proof away from the utility with respect to the reasonableness of its rates, insofar as that burden is allocated by the Act. City I, 13 Ill.2d at 617. That remains true today.

Moreover, the Court noted that under our then-existing practice - to "allow rate increases based on an anticipated increase in the cost of natural gas to go into effect without suspension," id. at 618 – no proceedings were conducted regarding the reasonableness of gas-commodity rate revisions[38]. Thus, the court characterized the choice between a rider and a series of un-suspended gas rate revisions as "a question of preferable techniques in utility regulation," reviewable only for abuse of discretion. Id. However, because of the above-quoted provision in Rider ICR, our statutory power to initiate a proceeding in which Peoples Gas would carry the burden of proving the reasonableness of Rider ICR would be circumscribed by the rider itself.

In A. Finkl v. Illinois Commerce Commission, 250 Ill.App.3d 317(1993), the Court of Appeals overturned our ruling that Commonwealth Edison ("ComEd") could recover demand side management expenses through a rider, on the ground (among other grounds) that we had violated the rule against single-issue ratemaking. The Court explained the rule: "instead of considering costs and earnings in the aggregate, where potential changes in one or more items of expense or revenue may be offset by increases or decreases in other such items, single-issue ratemaking considers those changes in isolation, ignoring the totality of circumstances." Id. at 325.

In CILCO v. Illinois Commerce Commission, 255 Ill.App.3d 876 (1993), the Court of Appeals upheld our decision, in an industry-wide proceeding, to allow rider recovery by all affected utilities for legally required coal-tar cleanup costs. The court emphasized

[37] Since Peoples Gas did agree to amend Rider ICR to include an annual reconciliation of prudently incurred main replacement costs, prudency and reasonableness must be properly distinguished. Prudency (which we have regarded as an "essential feature" of a rider, CILCO, Docket. No. 90-0127, Order (Aug. 2, 1991)) tests whether a cost is eligible for recovery. Reasonableness tests whether a rate has been properly and lawfully formulated to reflect eligible costs and associated benefits. Essentially, a prudent cost is a component of a reasonable rate. Thus, the fact that a cost is prudently incurred does not necessarily mean that the rate that recovers that cost is reasonable.

[38] Given our lack of authority to review federally determined gas rates, reasonableness proceedings would presumably have been superfluous.

our finding that "these costs will vary widely from year to year depending on the type of remediation activities" and concluded that, unlike the costs in Finkl, they were "the type of unexpected, volatile and fluctuating costs which are more efficiently addressed through a rider." 255 Ill.App.3d at 885. CILCO was reviewed by the Illinois Supreme Court in Citizens Utility Board v. Illinois Commerce Commission, 166 Ill.2d 111 (1995), which held that "the proposed recovery through a rider mechanism, *outside the context of a traditional rate proceeding*, does not violate the prohibition against single-issue ratemaking." 166 Ill.2d at 139 (emphasis added). Unlike the instant case, the "[W]e are not faced with the Commission's treating a single-expense item within the context of a general rate case." Id. at 137-38.

In City of Chicago v. Commerce Commission, 281 Ill.App.3d 617 (1996) ("City II"), the Court of Appeals affirmed our Order authorizing ComEd to collect municipal franchise fees through municipality-specific riders. Such fees had previously been recovered in the aggregate through base rates paid by all customers throughout ComEd's service territory. Although municipal franchise fees are typically predictable and stable, the court stated that nothing in prior precedent[39] "limits the use of a rider only to those cases where expenses are unexpected, volatile or fluctuating." 281 Ill.App.3d at 628.

The court underscored, however, that "[r]iders are closely scrutinized because of the danger of single-issue ratemaking," id., which is "prohibited because it considers changes in isolation, thereby ignoring potentially offsetting considerations and risking understatement or overstatement of the overall revenue requirement." Id. at 627. The court concluded that the franchise fee riders under review did not constitute single-issue ratemaking because "they did not have any impact whatsoever on Edison's overall revenue requirement" and were "'without direct impact on the utility's rate of return.'" Id. at 629.

The foregoing decisions plainly confirm that the Commission has discretionary latitude under the Act to authorize rider recovery in the proper cases. But they also unambiguously establish that the prohibition against single-issue ratemaking (as well as the test year rule) remains in place in rate cases[40]. The Utilities know this. "The only conditions that have been established as prerequisites for riders is [sic] that in appropriate circumstances, *they do not violate test year or single issue ratemaking proscriptions*, or that they reflect certain cost behaviors or unique circumstances." NS-PGL BOE at 60 (emphasis added). Thus, the courts have consistently held that when a utility's actions may affect its overall revenue needs in disparate ways, all impacts of such actions - both expenses and savings - must be considered and balanced in ratemaking[41]. Since the record here does show that accelerated main replacement will tend to generate certain savings, the single-issue ratemaking rule cannot be avoided.

[39] The court specifically cited Finkl, *supra*, and City I (which it erroneously identified in that context as "Citizens Utility Board").

[40] The rule against single-issue ratemaking and the test year rule were not discussed in City I, the seminal case upholding our authority to use automatic adjustment riders.

[41] This principle has been reiterated in proceedings not involving riders as well. One pertinent example: "it would be improper to consider changes to components of the revenue requirement in isolation. Oftentimes a change in one item of the revenue formula is offset by a corresponding change in another

Nonetheless, Peoples Gas insists that the costs of an accelerated main replacement program would be "unique." E.g. NS-PGL BOE at 64. Even if that were correct - and the Commission disagrees (discussed below) - it would not matter. In rate cases, "unique" issues are not exempted from the rule against single-issue ratemaking. That rule "requires that, in a general base rate proceeding, the Commission must examine all elements of the revenue requirement formula to determine the interaction and overall impact any change *will* have on the utility's revenue requirement, including its return on investment." Citizens Utility Board, 106 Ill.2d at 138 (emphasis in original). We are empowered to accord rider treatment to "unique" costs *outside of* base rate proceedings, not within them (where the single-issue ratemaking rule cannot be disregarded).

On exceptions - and for the first time - Peoples Gas suggests that Rider ICR could be harmonized with the single-issue ratemaking prohibition by including an offset against Rider ICR capital costs of "amounts reasonably attributable to leak repair savings and reductions in deferred taxes occasioned by accelerated main replacement program. [Peoples Gas] could be required to calculate these savings based upon the past year's activity in the annual reconciliation filing, with…appropriate credits." NS-PGL BOE at 63. Staff responds that Peoples Gas could have included a savings offset in Rider ICR at any time while the evidentiary record was still open, but only presented the idea, in general terms, after an adverse recommendation on Rider ICR in the Proposed Order. "[I]t is simply not possible to accord any reasonable review to this new proposal offered in [PGL'S BOE]." Staff RBOE at 49. Furthermore, Staff maintains, the single-issue ratemaking problem is still inherent in the rider." Id. The AG contends that PGL's general proposal fails to capture all the savings PGL's witnesses attribute to accelerated cast iron main replacement (principally, operations and maintenance savings). AG RBOE at 52.

The Commission agrees that Peoples Gas's suggestion is too general[42] and too late to be meaningfully considered, by the parties or by us, at this stage in the proceedings. Also, main replacement costs are capital costs, which need to enter rate base before associated revenues (in the form of a return) can be received. We also hold, in concurrence with the AG, that even Peoples Gas's general description of its suggested offsets shows that all claimed savings have not been included[43].

Ultimately, Peoples Gas's arguments in support of Rider ICR detach from their legal moorings and become a policy plea. "There is nothing about the costs that would be recovered under Rider ICR that are not the subject of routine, traditional Commission ratemaking. What is involved is merely a policy decision to employ a new rate design

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component of the formula. For example, *an increase in depreciation expense* attributable to a new plant may be offset by a decrease in the cost in the cost of labor due to increased productivity, or by increased demand for electricity." BPI v. Illinois Commerce Commission, 146 Ill.2d 175, 244 (1991) (emphasis added).

[42] For example, merely mentioning deferred tax savings (which is all Peoples Gas does in its BOE) is insufficient as a proposal. As Peoples Gas's witness stated in filed testimony, the effect of ICR on deferred taxes is a "straightforward, though very complicated calculation." NS-PGL Ex. JFS-3.0 at 8-9.

[43] *E.g.*, the offsets would not include the reduced maintenance costs that Peoples Gas associates with elimination of low pressure regulating stations. NS-PGL Ex. ED-1.0 at 18.

approach for a truly unique undertaking, as occurred in City I." NS-PGL BOE at 64. Peoples Gas's description of the routine nature of its main replacement investments is correct.

The financial assurances that ostensibly justify a Rider ICR on policy grounds were, and are, available to Peoples Gas under ordinary ratemaking. The fact that Peoples Gas elected not to seek recovery for accelerated main replacement through base rates is significant. Presumably, this is because there is no clear likelihood that standard municipal improvements and private development projects will unfold at a rate or scale that exceed the historic levels reflected in base rates. Nor, apparently, is there clear likelihood that projects that do arise will implicate significant spans of CI/DI mains that Peoples Gas has prioritized for replacement through its MRI analysis (which are also the mains more likely to experience the cost-producing leaks Peoples Gas hopes to avert). Thus, even with Rider ICR, Peoples Gas did not choose to commit to accelerated main replacement. Insofar as Peoples Gas would like to quicken the pace of system modernization, it is free to craft a concrete and sustainable proposal for doing so, and to request base rate recognition of associated investments

We find Staff's argument to be compelling. Staff asserts Part 656, the Commission's preexisting rule for qualifying infrastructure plant surcharge for water and sewer utilities, is a template for Rider ICR. Tr. at 21. We believe that a Rider scripted in accordance with the strictures of Part 656 would ensure that only the costs of the CI/DI Main Replacement Program are recovered through the rider, since the rider would have to meet specific criteria in order to be eligible. Staff Ex. 13.0 at 18-20. The legislature has given guidance on the appropriate methodology to be utilized when drafting a Rider for the Commission's consideration. In the instant case, we observe that Peoples Gas has failed to utilize the parameters of an appropriately drafted Rider.

The Commission is cognizant of the potential benefits of an accelerated CI/DI main replacement program. To be sure, the Commission is keenly aware of the critical need to update and replace the infrastructure that we depend on to deliver our nation's natural gas and energy supply. Unfortunately, in this particular instance, Rider ICR is a deficient vehicle for such a goal. As Staff aptly points out, proposed Rider ICR provides no estimate of the costs or savings under the accelerated program, nor does it demonstrate that the savings will outweigh the additional costs paid by ratepayers under the proposed rider. Staff Ex. 8.0, pp.36-37. Given the paucity of Rider ICR's provisions, the Commission must reject it. In doing so we would like to be clear that the Commission intends no prejudice toward any base rate treatment Peoples Gas may subsequently seek for CI/DI main replacement expenditures. Indeed, the Commission commends Peoples Gas's improvement of its distribution system.

The Commission both supports and understands the need for system modernization. It is clear that Peoples Gas, and probably some other Illinois utilities, have infrastructure components that date back to the turn of the 20th century and many still use technologies that were state-of-the-art eighty years ago. We also recognize that new technology is being applied in every other sector of our economy, to the benefit of both consumers and companies (by lowering costs and providing new products and choices).

This rider proposal reflects a need for the Commission to provide guidance to utilities on the information the Commission needs, at a minimum, to evaluate system modernization proposals, beyond Part 656 and Section 220.2 of the Act. Peoples Gas presented this Commission with no quantitative evidence, no benefit-cost analysis, and no plan as to why or how a $1.0 billion dollar, forty- to forty-five- year investment, should be completed at a much faster rate (i.e., within the next seventeen to twenty-two years).

And yet, we suspect that there are many benefits – quantitative and qualitative – that could have been identified, enumerated and quantified in support of an enhanced system modernization initiative. It is our view that Peoples Gas could have quantified the benefits of Rider ICR. Absent a clear evidentiary record which demonstrates the benefits of the Rider ICR, the Commission must reject the proposal.

So, we are left with a dilemma. To ensure continued reliability, we lean towards increased system modernization, rather than less, all other things being equal. In a general sense, the application of modern technology to the utilities and networks that we regulate and upon which our economy depends makes simple common sense. But unless the proponents of the modernization initiatives provide a more compelling rationale in terms of identifying and quantifying reduced system costs and increased customer benefits, we will never be persuaded that modernization is in the best interest of the ratepayers. Thus, we are likely to have less system modernization in Illinois, rather than more, and the consumers and businesses in Illinois will be the worse for it.

In the case of Rider ICR, the Utilities' proposal is insufficient for the Commission to approve it. It might have been easier to approve the rider had the Utilities included, or the Staff or the Intervenors' elicited, such information as: a detailed description and cost analysis of the proposed system modernization; an identification and evaluation of the range of technology options considered and analysis and justification of the proposed technology approach; a detailed identification and description of the functionalities of the new system, related both to system operation as well as on the customer side of the meter, as well as an identification and justification of functionalities foregone; analysis of the benefits of the system modernization, both to system operation as well as to customers; these benefits should include reductions in system costs as well as an analysis of the range and benefits of potential new products and services for customers made possible by the system modernization; an analysis of regulatory mechanisms to allow companies to both recover their costs of system modernization as well as to flow reduced system costs back to customers; and an identification and analysis of legal or regulatory barriers to the implementation of system modernization proposals.

Since we reject Rider ICR, there is no reason to address Staff's alternative Rider QIP and we will not do so.

C. Rider EEP (Merits of Energy Efficiency Programs and Rate Treatment)

1. Utilities

a) Merits of Energy Efficiency Programs

In In re WPS Resources, Inc., Docket 06-0540, the Commission approved a set of conditions under which the merger proposed in that docket was approved. Condition 27 required that Peoples Gas and North Shore propose a new ratepayer funded energy efficiency program of not less than $7.5 million per year. The Utilities maintain that their proposal, embodied in Rider EEP, satisfies the merger condition.

Utilities witness Rukis testified that the program will be governed by a Governance Board, consisting of five voting members (ELPC, the Utilities, the City of Chicago, a consumer advocacy group, and a North Shore service territory government or consumer member), and one non-voting member from Staff. PGL Ex. IR-1.0 at 6-7. This membership would insure the independence of the Governance Board, and therefore the entire program, from the Utilities. The Governance Board would evaluate and select a Program Administrator, a Contract Administrator, and a Program Evaluator. Id. at 7-8. The independent Contract Administrator would help establish budgets and approve expenditures. Id. at 8. The independent Program Administrator would develop the actual programs, and make reports to the Governance Board. Id. The independent Program Evaluator would make periodic audits and check the performance of the program against established criteria. Id. at 9. The ministerial function of a Fiscal Agent, who would maintain the accounting reports and pay invoices approved by the Contract Administrator, would be at one of the Utilities. Id.

The Utilities anticipate that much of the program would be directed to rebates and other incentives, typically supporting new energy efficient technologies and other gas-saving techniques available for purchase by gas consumers. These could include more efficient furnaces or improved weatherization. PGL Ex. IR-1.0 at 11-15. The programs would be publicized through the media and point-of-sale locations. Id. at 17.

The Utilities note that their proposal of a ratepayer-funded energy efficiency program – leaving aside the issue of whether it is implemented through a rider mechanism – is enjoying broad support from the parties. More specifically, ELPC strongly supports the program, and the City, AG, and CUB support the program as well.

Staff, the Utilities point out, is the only party to oppose the proposed Energy Efficiency Program on its merits. The Utilities believe Staff's worries and quibbles are overstated, and can be summed up in one sentence from Staff's brief: "Staff does not support using utility rates to fund conservation programs." Staff Init. Br. at 205. For their part, the Utilities believe that the proposed program, borne of the Integrys affiliates' experiences in other states, and of the observation by the Utilities and the ELPC as to how programs work in other states, justifies this program for Illinois.

Staff considers the program "unfair," the Utilities note, because not everyone will necessarily participate. Staff Init. Br. at 203. In the Utilities view, however, this is a rather small argument. Many things work this way, including almost everything paid for

by taxes. Taxes pay for roads that many citizens will never drive on, and fire fighters that most people, thankfully, may never call. Does this make taxes "unfair?" Surely Staff would not take the argument quite that far. Given all the positive effects of a well-designed energy efficiency program, the Utilities argue, it should not be considered so unfair as to be not worth undertaking as long as the benefits are equally available to all customers. The broadly constituted Governance Board, reporting to the Commission, should be able to design a program with broad appeal. Id. at 3.

Staff also considers the program "inefficient" on account that high prices should do the work. Staff Init. Br. at 204. Even with high prices in the near term, the Utilities believe that some customers will make better choices with an extra incentive. NS--PGL Ex. IR-3.0 at 2. Staff seems to assume that the program will result in measures that are not cost-effective. But if cost-effective measures are chosen – and there is enough experience around the Midwest at this point that good program directors can find such measures – this should not be a real concern. Id. at 3.

As to governance, Staff complains that it is inefficient. The Utilities do not agree, but ultimately will abide by whatever structure the Commission orders. Staff's proposal is for a Director that has central control. That works in some other programs, and the Utilities can live with it. The Utilities' focus in setting up the proposed governance was to place a high value on independence from the Utilities. Id. at 5. The Utilities understand that many people would feel that the Utilities have insufficient motivation for the program to be successful if they were to control it. Their organizational structure too, is not the only way to set up a program. But, as proposed, it would be independent.

A funding level of about $7.5 million is appropriate, the Utilities assert, given the size and type of their respective service territories. Id. at 4-5; NS--PGL Ex. IR-2.0 at 2-3. Accordingly, the Utilities urge the Commission to approve this program.

b) Rate/Rider Treatment

The Utilities' proposed Rider EEP, they explain, will recover their expenses of providing funding for the costs of energy conservation and efficiency programs for their customers through qualified independent third party administrator(s). PGL Ex. RAF-1.0 at 42. The purpose of Rider EEP is to compute, on an annual basis, a monthly charge per customer for each applicable service classification to recover the incremental expenses that support the development and implementation of those energy efficiency programs. PGL Ex. VG-1.0 REV at 40; NS Ex. VG-1.0 3REV at 35. The Utilities are proposing rider recovery for expenses related to the proposed energy efficiency programs for two reasons. First, they note, there is precedent for recovering such expenses through a tariff rider. Previously, Peoples Gas had offered energy efficiency programs as part of a statewide least cost planning initiative and recovered such expenses through Rider 16, Adjustment for Incremental Costs of the Energy Conservation Plan. Second, the Utilities observe that legislation has been offered that may ultimately lead to a statewide energy efficiency initiative. As there is potential for the Utilities' customers to fund energy efficiency programs under a statewide initiative, the Utilities would not want to burden its customers with the cost of multiple programs. PGL Ex. VG-1.0 3REV at 41-42.

Utilities witness Feingold testified that Rider EEP is a necessary complement to the Utilities' proposed energy conservation and efficiency programs, that Rider EEP ensures that the defined level of funding is made available on an ongoing basis to the chosen service providers, and that the Utilities' applicable customers will be charged only for the program costs actually incurred as the types and mix of implemented programs changes over time. PGL Ex. RAF-1.0 at 42; NS Ex. RAF-1.0 at 39. Further, program cost recovery is considered to be an essential factor in order to achieve utility-sector energy efficiency programs and there should be a clear, reliable and timely regulatory process in place to ensure the recovery of these ongoing expenditures. A rate making mechanism that ensures predictable and timely recovery of energy efficiency and conservation program costs is particularly important for the Utilities because there are added uncertainties surrounding the precise timing of the rollout of their energy efficiency and conservation programs. The uncertain timing with regard to forecasting along with the level and incurrence of program expenditures make Rider EEP well suited for rider treatment as the Commission has acknowledged in other cases. NS-PGL Init. Br. at 135. This programmatic uncertainty makes it difficult to develop a specific amount to represent each year's costs of program implementation. As a result, it is appropriate and necessary for Peoples Gas and North Shore to have the ability to recover such costs through a ratemaking mechanism that can accommodate the anticipated variations in budgeted versus actual costs from year to year. PGL Ex. RAF-1.0 at 43; NS Ex. RAF-1.0 at 40.

The Utilities note that while not recommending a rider, ELPC witness Kubert agrees to the uncertainty regarding the varying levels of expenditure in an EEP program such as the one proposed here. As such, Mr. Kubert acknowledges that in applying spending levels to People Gas and North Shore revenue, an energy efficiency program for their customers would be $8.7 million on the low end up to $36.5 million on the high end. ELPC Ex. 1.0 at 6-7. The Utilities observe that Rider EEP expenses are only known today because the Utilities have agreed to an amount as approved by the Commission.

The Utilities point out that Staff witness Hathhorn recommended certain language changes for Rider EEP and proposed that the Utilities establish an annual reconciliation procedure and internal audit process, as well as change the monthly tariff filing date. Staff Ex. 1.0 at 29. The Utilities would have the Commission know that they have agreed to the revisions suggested by witness Hathhorn. NS-PGL Ex. VG-2.0 at 51.

While the Utilities would accept a deferred account procedure for handling EEP expenditure program recoveries so long as the deferred account process was annual, as opposed to between rate cases, the Utilities do not believe that the objections raised by witnesses Messrs. Brosch and Lazare flatly opposing the rider mechanism are valid. First, the Utilities claim, it is fact that such costs have been previously recovered in a rider is a cogent and persuasive reason for employing a rider to recover EEP programs costs. Not only is the fact indicative of the Commission's employment of riders in general, the Utilities argue, but it also is very indicative that the type of costs to be recovered are highly suited for rider treatment. Indeed, they point out, the difficulty in forecasting and uncertain timing of the level and incurrence of expenditures are the

same features that the Commission has determined justify rider treatment in other cases, such as in the CILCO case. In addition, the size of the expenditures to be recovered under a rider should have no bearing on whether the rider should be employed if the costs otherwise are suitable for rider treatment. In this case, the pending legislative proposals discussed by Ms. Grace offer another reason to have a rider in place to capture any eventual additional related costs. In general, the Utilities observe, the objections lodged by the opponents for rider treatment of EEP program costs are more philosophical than anything—those parties simply do not like riders because they view them as "piecemeal" and "nontraditional". These are unpersuasive positions, the Utilities assert, in view of the Commission's long employment of riders.

As the courts point out, "[r]iders are useful in alleviating the burden imposed upon a utility in meeting unexpected, volatile or fluctuating expenses". Finkl, 250 Ill. App. 3d at 327. The Utilities maintain that Rider EEP costs clearly meet these criteria. Other parties have argued that because the Utilities have agreed to spend $7.5 million, i.e., a fixed amount, a rider cannot be used to recover these expenses because where the amount is known, it cannot possibly be "unexpected, volatile or fluctuating". AG Init. Br. at 119; Staff Init. Br. at 210-211; City-CUB Init. Br. at 89-90; ELPC Init Br. at 10-11. The Utilities disagree.

They note that Finkl did not deal "specifically with the very type of expenditure that Peoples Gas and North Shore would recover through Rider EEP". City-CUB Init. Br. at 89. In Finkl, the Utilities observe, the court reversed the Commission's order which utilized a rider to recover costs associated with demand-side management programs because the Rider 22 expenses as the Court found "involve payroll …; personnel training, education and travel; contractors and consultants costs; out of pocket promotion and computer costs; and conducting workshops". Finkl, 250 Ill. App. 3d at 327. These very costs were within the control of the Utility. This is certainly not the case with the Utilities' proposed Rider EEP expenditures, which lack the certainty that could be used to predict in advance expenditures from month to month and year to year and may even fluctuate. NS-PGL Init. Br. at 135.

Moreover, the Utilities assert that the test of whether a rider is justified centers around whether the costs are controllable or are predictable with any certainty. The expenditure for the energy efficiency program at hand, they argue, is neither controllable by the Utilities nor predictable with any certainty. The costs are a function of when the Board approves the funding of projects and this is a function entirely independent of the Utilities. The Utilities believe it difficult to imagine a category of costs that are so totally out of the control of the Utilities and so subject to being expended at times which are dependent upon the actions of third parties. In other words, the Utilities argue, the EEP costs fall squarely into the category of costs that the Illinois courts have found to warrant rider treatment. CUB I, 166 Ill. 2d at 1093.

In their undifferentiated opposition to riders, the Utilities observe the opponents to simply ignore that under the Utilities' proposed Rider EEP, customers would receive immediate and direct benefits of reduced base rates to the extent the expense associated with the energy efficiency and conservation programs decreased from the level used to establish the initial adjustment under the Rider. NS-PGL Ex. RAF-2.0 at

49. Additionally, the Utilities maintain, under Rider EEP customers will not be subjected to the risk of overpaying for a higher level of expenses associated with the energy efficiency and conservation programs when the expenses decrease from the program's initial funding level. According to the Utilities, if this expense component were recoverable through base rates, customers would not benefit from lower rates whenever program costs decreased from the level assumed in the Companies' rate cases. NS-PGL Ex. RAF-2.0 at 51.

The Companies point out that utilities in various states such as Idaho, Massachusetts, Minnesota, Vermont, and Washington have received regulatory approval to recover the direct costs of their energy efficiency and conservation program through tariff provisions such as adjustment riders. PGL Ex. RAF-1.0 at 43-44; NS Ex. RAF-1.0 at 40. Clearly, there is an explicit recognition by the regulators in those states that assured recovery of energy efficiency costs is a necessary step in addressing the barriers many utilities face to investing in more energy efficiency measures. As such, the Utilities argue, the Commission should approve Rider EEP; it would be in step with the evolving policy making trends across the country.

2. Staff

a) Merits of Proposed Energy Efficiency Program

In Staff's view, the Utilites are asking ratepayers to fund a program that is not equitable. In other words, it is funded by all ratepayers, but the direct benefits only accrue to a limited subset of ratepayers. Some ratepayers will see few or no benefits and these may be homeowners that have just upgraded their houses or bought new residences. Others may be renters whose apartment manager does not take advantage of the program. And still others will view the return on their conservation investment as too low even with the benefits provided by an EEP. According to Staff, It is impossible to compare the cost that one individual has to pay with the benefits that others receive, or to determine that one individual's gain is worth more than another individual's loss. Id. at 32-36.

The EEP is also inefficient, Staff argues, because the conditions that are most likely to lead to demand for EEP services are those that already provide the best incentive to invest in conservation without an EEP. As gas prices rise, the return to saving gas usage increases, and there are more incentives for individual businesses and consumers to invest in conservation technology without any utility program. No base case for conservation spending absent the EEP has been established, Staff notes, and thus there is no way to measure the incremental effect of the EEP. While the benefits are likely to outweigh the cost for ratepayers receiving program benefits, it is less clear that this is true for ratepayers as a whole. For the entire program to have net benefits, Staff asserts, the value of the gain in technical efficiency from the program must be higher than the cost. Id. at 33-36. And, even if the EEP has net benefits as a whole, Staff does not believe an efficient outcome is guaranteed. Some customers may be induced to invest in projects that are not cost effective by themselves, but the whole program may still have net benefits on average. In Staff's view, efficiency requires that the last individual project undertaken have net benefits.

Staff does not support using utility rates to fund conservation programs. It is concerned that such programs may reduce economic efficiency. According to Staff, ratepayers who may be investing at efficient levels absent the program might be induced to start investing in too much conservation by investing in projects that have negative net returns. This reduces economic efficiency. In contrast, a program financed through an income or property tax would have a smaller decrease in efficiency.

Staff notes that various parties to the docket make claims of aggregate or system-wide benefits. Staff points out that the claims are not well-founded. The parties have offered only vague assertions to bolster their claims for large system-wide benefits. Staff strongly disputes the parties claim that it has been demonstrated that EEP can lower gas prices in Chicago.

Staff also finds the EEP design to be flawed. Staff has several concerns with how the EEP is to be administered. Foremost, Staff considers that the lines of command are not clear, i.e., it is not clear who controls which functions and who makes what decisions. This is important to Staff, since it does not appear that the Administrators are accountable to anyone. Staff believes that the organizational chart for the program (NS Ex. IR-1.1 and PGL Ex. IR-1.1) demonstrates the validity of this concern. There is an arrow from the Control Administrator to the Board and an arrow from the Board to the Program Administrator, but the chart does not indicate to whom the Administrators report. There also does not appear to be any way for the Board to limit administrative costs. If administrative costs are too high, Staff asserts, the extra costs will seriously undercut the EEP's effectiveness. Staff Ex. 12.0 REV. at 36-37.

Staff recommends that the organization be one that is accountable and efficient. The Board should appoint a Director that has clear authority to act both with respect to employees and programs. Employees should be enabled to select and administer the programs under the authority of the Director. It is not clear to Staff that the Program Evaluators need to be a separate group of employees such that the Director should use the inputs of the employees to select programs that the employees can evaluate. One way to help make the process effective is to conduct periodic management audits and use annual reports about the programs' effectiveness. Staff urges that these changes should be made no matter the method of rate recovery, i.e. rider or base rates. Id. at 37. An important control that the Commission should impose on the EEP is to have a binding constraint on the amount of administrative costs that are incurred, and by requiring the Companies to periodically report their EEP overheads. Id.

Finally, in the event that the Commission approves EEP, Staff agrees with the Companies' witness Rukis that EEP not be funded above $7.5 million per year. In addition Staff recommends that the Commission order the Companies to be responsible for the prudent choice of programs and efficient implementation of those programs. The Companies must be ultimately responsible for any EEP expenditures authorized. Id. at 38.

b) Proposal for Rider Recovery of EEP Costs

Staff observes that the Companies' proposed Rider EEP is designed to charge, recover, and reconcile the budgeted and actual costs of an energy efficiency program

for the eligible rate classes S.C. 1H and S.C. 2. North Shore Ex. VG-1.0 2REV at 35-36. The Companies propose a constant annual budget of $7.5 million, proportionally divided between the two Companies, based on their share of the rate base. Id. at 38. The Companies proposed that the rider work thusly: in December of 2007, the Companies would calculate the "Effective Component" by dividing the 2008 budget ($7.5 million) by the forecasted number of customers (861,134) and dividing it by 12 months to determine the per customer monthly increase for 2008. Id. at 35-36. Under or over estimating the budget will then be reconciled in March of 2009, when the Companies will calculate how much customers over or under paid in 2008. That amount, with interest, will then be amortized over the next nine months. Id. at 36.

The process then continues much the same way, except, the Companies, in accordance with their proposal, can carry-over up to 75% of the 2008 budget into 2009; subsequently they will carry 50%, 25%, and then 10% through the life of the program. (Id.) In December of 2008, the Companies will once again determine the "Effective Component" or customer charge for 2009 customers based on forecasted customer numbers. This charge will then be reconciled in March 2010, where the Companies will calculate if they should recover additional funds for program expenditures above the combined 2009 budget and the carry-over budget from 2008, or refund an over recovery of customer charges monies unspent under the carry-over limit. Id. This reconciliation will then be submitted to the Commission in a docketed reconciliation proceeding. Staff Ex. 1.0, Attach. D, p. 3. The Company will also file, with the Accounting Department of the Commission, an annual audit on July 1 of each year. Id.

Staff notes that the Commission can approve "the direct recovery of unique costs through a rider when circumstances warrant such treatment." CUB v. ICC, 166 Ill.2d at 136. One standard for recovery of expenses through a rider is that the expense to be recovered is volatile, unexpected, and likely to fluctuate. CILCO v. ICC, 255 Ill.App.3d at 885. In Staff's view, however, the Companies have not demonstrated that costs underlying the operating expenses associated with an energy efficiency program are or will be, volatile, fluctuating, or unpredictable.

According to Staff, the Utilities' arguments in support of rider treatment fall short. First, Staff notes that the prior rider recovery of the incremental cost of energy efficiency and conservation measures occurred in the context of conducting pilot energy conservation programs to test the effectiveness of various types of conservation programs by all utilities. In re An Investigation Concerning the Propriety and Appropriateness of the Development and Implementation of Energy Conservation Programs by The Peoples Gas Light and Coke Company, Docket No. 83-0034, 1993 Ill. PUC LEXIS 48, at 2 (Order Feb. 10, 1993); In re An Investigation Concerning the Propriety and Appropriateness of the Development and Implementation of Energy Conservation Programs by The Peoples Gas Light and Coke Company, Docket No. 83-0034, 1989 Ill. PUC LEXIS 417, at 3 (Eighth Supp. Interim Order, Nov. 8, 1989)) This is hardly the situation in the instant case. Further, Staff observes that the Companies cite to no order by the Commission explaining the basis on which rider recovery was approved, so that the fact of prior approval is of little assistance in evaluating the current proposal. Moreover, while the Commission did generally find that the costs of energy

efficiency and conservation measures were recoverable through riders in the 1990s, that practice was rejected by the courts. *See* A. Finkl & Sons Co. v. Illinois Commerce Comm'n, 250 Ill. App. 3d 317 (1st Dist. 1993).

In Staff's view, Ms. Grace's testimony completely contradicts any argument that such costs are volatile, unpredictable, or fluctuating. The costs of the Companies' proposed energy efficiency program is budgeted at $7.5 million, but the Companies, with their experience in offering energy efficiency programs know, and Ms. Grace testified, that it would take a few years to build up to the budgeted annual amount. When the Companies drafted Rider EEP, they predicted a slow start to the programs and embedded a mechanism that allowed for a carry over of 75% of the budget in the first year, 50% in the second, 25% in the third, and 10% every year there after. NS Ex. VG-1.0 2REV at 36; PGL Ex. VG-1.0 at 40.

Furthermore, Staff believes that the discretion offered under the rider for the Companies to carry over amounts from one year to the next raises a concern. This significant funding flexibility could result in a significant gap between the budgeted expenditures and the amounts actually spent. This would create a gap between the policy objectives guiding the Commission's approval of the rider and the amount that is actually spent on the associated programs. Staff Ex. 8.0 at 34. According to Staff, the magnitude of carry-over provision raises further questions about the program itself. The level of spending flexibility raises questions about the degree of progress in planning and developing the programs and what kinds of programs ratepayers will receive for their contributions to Rider EEP. Id. For this reason, Staff cannot recommend that the Commission blindly subject ratepayers to an out-of-rate-case rate increase.

Staff notes Peoples Gas and North Shore argue that the size of the expenditures to be recovered under a rider should have no bearing on whether the rider should be employed if the costs are otherwise suitable for rider treatment. Id. Staff does not agree. Staff observes that there is a cost associated with implementing and administering riders and this cost can be significant. Thus, if the revenues to be recovered under the rider are small, then the costs could outweigh any possible benefits. In any event, the amount of revenues to be recovered is an important consideration in deciding whether to approve the rider.

If the Commission determines it is appropriate for the Companies to recover funds necessary to implement various energy conservation and efficiency programs through a rider mechanism, Staff recommends the Commission adopt the language changes which are reflected in legislative style in Attachment D, Staff Revised EEP, to Staff Ex. 1.0. The changes are: 1) to reflect an annual reconciliation with possible adjustments to ensure the EEP is in compliance with the tariff; 2) to change the monthly filing date to allow for Staff review prior to the effective date; and 3) to require the Companies perform annual internal audits on compliance of the EEP. Staff notes that the Companies stated no opposition to these proposals. NS-PGL Ex. VG-2.0 at 51.

3. ELPC

a) Merits of Proposed Energy Efficiency Program

The ELPC maintains that consumers who directly participate in well-designed energy efficiency programs benefit from reduced gas usage and lower bills. Energy efficiency measures can cost half per Mcf saved compared to the cost of natural gas. According to the ELPC, a review of leading utility natural gas energy efficiency program results indicates that such programs typically have more than a 2 to 1 'benefit to cost ratio,' and save natural gas at a cost of around $2.50 per Mcf. That is less than half the forecasted wholesale cost of natural gas over the next 10 years." ELPC Ex. 1.0.

The ELPC points out that these savings are documented in the many programs under operation in other states. Natural gas energy efficiency programs have been implemented by utilities in over 20 states, including Iowa and Wisconsin. Id.

> In 2005, the average residential natural gas consumption in Iowa was 791 therms, in Wisconsin 823 therms, in Minnesota 942 therms. In contrast, the average Peoples Energy residential customer used 1,231 therms and North Shore Gas customer used 1,392 therms. This comparative energy consumption data is attached as Exhibit 1.2. While there are a number of factors driving these differences, including the size and age of the housing stock, it suggests that long-established energy efficiency programs in these neighboring (and colder) states have played a role in reducing gas use. It also suggests that there is significant untapped energy efficiency potential in Illinois.

Id.

The ELPC notes, for example, that if a residential customer made an investment that has an average cost of $100 per year over the life of the energy efficiency improvement (normally 15-20 years), assuming a conservative $2 payoff on $1 investment, on a yearly basis, he or she could recoup that $100 plus the approximately $100 average rate increase that Peoples small residential heating customers would pay under the Companies' proposed rate increase. According to the ELPC, this does not even consider that it is the norm within such programs to provide participants with energy efficiency improvements at discounted rates so the payoff to the customer on their investment would likely be even higher.

To be sure, the ELPC argues, a goal of in excess of $100 in annual savings per residential participant is extremely reasonable. In Massachusetts, a program providing rebates on high-efficiency furnaces is seeing savings of 185 therms annually per customer. ELPC Ex. 1.3 at 50. In Vermont, a residential retrofit program that offers energy audits and across the board recommendations of energy efficiency measures is providing individual customers with savings of 510 therms annually. Id. at 72. Finally, a similar residential retrofit program in New York is providing individual customers with annual savings of 347.9 therms. Id. at 64. Consequently, the ELPC suggests, it would be reasonable to expect savings in Illinois comparable to the median program in New York. At a conservative estimate, reducing gas usage by 347.9 therms annually would provide customers with $141.25 in annual savings. Such savings would more than

cover residential participants' investment in the program and improvements and even offset part of the Companies' proposed rate increases.

According to the ELPC, the proposed energy efficiency program would benefit Illinois' overall economy. The ELPC points out that, there is essentially no natural gas produced in Illinois, and as such, the state is entirely dependent on natural gas imported from other states and countries. PGL Ex. IR 1.0, lines 89-90. Every dollar that consumers spend on the commodity portion of their natural gas bill, the ELPC argues, is a dollar transferred out of Illinois' economy. The total drain on Illinois' economy resulting from buying out-of-state natural gas is over $7 billion per year. ELPC Ex. 1.0.

In the ELPC's view, energy efficiency programs in Illinois also have the potential to produce a net gain of nearly 6,500 jobs and $220 million in additional net annual employee compensation in Illinois by 2010 and 13,000 net new jobs and $440 million in net additional annual employee compensation by 2020. Id. Ex. 1.0. In sum, the ELPC argues, energy efficiency brings an enormous benefit to Illinois' economy over buying out-of-state natural gas.

As a further benefit, the ELPC maintains that energy efficiency programs help to reduce total demand for natural gas, which puts downward pressure on natural gas market prices. While ELPC acknowledges that the Companies' proposed energy efficiency program alone might not affect wholesale natural gas prices, it is a step towards reductions in natural gas prices.

There are many aspects of the program which assures that dedicating funding to the EEP is a prudent expenditure. First, the ELPC points out, there is the accountability built into the structure of the program. As described in great detail in Company witness Rukis' testimony, the Companies have proposed a structure for the EEP that holds those responsible for the program accountable but also maintains the program's independence from the Companies. The Governance Board, whose members would be accountable to, and representative of, all interested parties, is at the top of the hierarchy of the program.

Second, the ELPC maintains that the proposal assures accountability through the numerous audits and evaluations. The Program Evaluator would perform periodic audits of the program, the ELPC explain, and prepare annual reports. Id. at lines 188-190. And, he or she would also provide other periodic evaluations or reports as required by the Governance Board. Id. at 190-93. The ELPC further notes that the Companies also recommend a periodic review by an independent third party to assess how well the overall structure and process of the programs are performing and whether any changes should be made. Id. at lines 211-32. Ultimately too, there would be accountability before the Commission. Because the Commission maintains authority over Peoples and North Shore and authority over the level of rates charged, the Commission maintains the ability to review how the program is running. Tr. at 104. Specifically, all reports, audits, and evaluations could be filed with the Commission and with exhibits added in the next rate case. Id. at 104-105.

According to the ELPC, the program is a prudent use of funds because it assures energy efficiency projects with high paybacks. Despite the fact that energy efficiency can save utility customers money, the ELPC contends that there is still underinvestment in energy efficiency in Illinois. By way of example, one can look at the market penetration of high-efficiency furnaces. In Illinois the market penetration is 30%, while in Wisconsin, where there has been an energy efficiency program for many years, the market penetration of high-efficiency furnaces is 70%. Tr. at 1421-22. The ELPC has well-explained the many reasons for the underinvestment in energy efficiency, to wit:

> lack of information regarding potential energy efficient improvements and their benefits; a focus on first-cost versus life-cycle costs when constructing buildings and buying appliances; uncertainty over length of time in homes which discourages longer payback investments; unreasonably short payback requirements by businesses; a tendency by builders to comply with minimal code requirements; and split incentives between landlords and tenants.

ELPC Ex. 2.0. Because energy efficiency costs less per MCF saved than natural gas, the ELPC asserts that energy efficiency programs and policies are necessary to increase the investment in energy efficiency to a level at which individuals and society will reap the most benefit. ELPC Ex.1.3 and 1.4.

The ELPC points out that the program has measures which assure energy efficiency projects with the highest paybacks. It is of record that "One of the first things that the governance board should accomplish is a market potential study which will further ensure the best and wisest use of available resources by identifying the opportunities to use the funds." Tr. at 97. There will also be a "bidding process that will ensure that we get the lowest-cost programs." Id. at 98. Given this telling evidence, the ELPC maintains that the EEP is a prudent expenditure and necessary to accomplishing broad adoption of energy efficiency measures.

Finally, the ELPC recognizes the Commission to have full authority to direct the adopting of energy efficiency programs in this rate case Order under its broad statutory authority. 220 Ill. Comp. Stat. 5/9-250. The ELPC points to language in numerous states as sources for this authority and asks that it be exercised in this case. And, the ELPC notes that the Commission itself has recognized that energy efficiency reduces energy costs for consumers when it stated that:

> We believe that smart energy efficiency programs will have two effects. First, they will lower the cost of heating for the home or business participating in the program. Second, targeted correctly, they will reduce the amount of high cost natural gas that Illinois has to buy, thus reducing everyone's costs, as well.

The Commission further indicated that:

> [S]mart energy efficiency programs . . . , targeted correctly, . . . will reduce the amount of high cost natural gas that Illinois has to buy, thus reducing everyone's costs, as well. . . . . Increased energy efficiency that decreases the individual household or business costs of natural gas and electricity

> and—at the same time—reduces the amount of high cost energy we have to buy—lowers prices for everyone and appears to be the premier option that Illinois has for lowering customer energy bills.

Northern Illinois Gas Company, Docket No. 04-0779, Order at 193 (September 20, 2005).

For all these reasons, the ELPC joins in asking approval of the Utilities' EEP in this case.

b) Proposal for Rider Recovery of EEP Costs

The ELPC maintains that recovery for the Energy Efficiency Program should be through base rates, and not a rider. In the ELPC's view, the mere fact that the EEP is a new program and new expense area for the Companies does not suffice for such treatment. Typically, the ELPC argues, the only expenses that justify riders are those which are outside the utility's control or are volatile and unpredictable. The energy efficiency program is not outside the utility's control—indeed, the utilities in this case are proposing the expenditure—and such is neither volatile nor unpredictable. ELPC Ex. 1.0. It may just be the opposite, i.e., stable and predictable, because it is fixed at the same amount every year.

The ELPC recognizes that specific legal standards must be met before rates can be recovered through a rider and the circumstances must "warrant such treatment." Citizens Utility Board v. Illinois Commerce Comm'n, 166 Ill. 2d 111, 138 (1995). As such, the expense must be volatile, unexpected, and likely to fluctuate. Id. In terms of facts, the ELPC considers the case of A. Finkl & Sons Co. v. Illinois Commerce Comm'n, 250 Ill. App. 3d 317 (1st Dist. 1993), to be precisely on point. In that case, the ELPC explains, the court was considering the appropriateness of the use of a rider for recovery of costs for a demand side management program, which in essence, is an energy efficiency program, and it held that demand side management costs could not properly be recovered through a rider because they were not volatile nor were they beyond the Company's control. Id. at 327. The court also noted that the rider was not proper because the amount of dollars to be recovered through the rider was not significant and the costs were recoverable through the usual base rate mechanism. Id. *Cf.* Citizens Utility Board v. Illinois Commerce Comm'n, 166 Ill. 2d at 138-39 (holding a rider appropriate because there were "wide variations and difficulties forecasting the costs" to be recovered). In the present case, where the program costs are a set $7.5 million per year, the ELPC believes that the costs cannot be described as volatile, unpredictable, or likely to fluctuate. According to the ELPC, a deferral accounting mechanism can be employed to track and reconcile differences between recovery through base rates and disbursements made under the program. GCI Ex. MLB-1.0 at 72.

4. GCI

a) Merits of Proposed Energy Efficiency Program

The GCI note that in the recent Peoples Gas/North Shore Gas merger proceeding, the Utilities agreed to propose to implement energy efficiency programs for

both companies, and in an annual aggregate amount of $7.5 million, to be funded by ratepayers. *See* Docket No. 06-0540, Appendix A, Conditions 27-30. The AG, the ELPC, CUB, the City, and other intervenors were signatories to the agreement. Between the approval of the merger settlement and the filing of this rate case, the Companies met with representatives from the AG's Office, ELPC and other stakeholders for discussions on implementation of the programs. In an effort to ensure that the energy efficiency programs are developed and marketed by individuals and entities with experience in the implementation of EEPs, the Companies and the aforementioned stakeholders agreed that a third-party Governance Board structure would provide an efficient foundation for program creation and implementation.

GCI notes that the Act makes multiple references to the mandate that utility rates be least-cost. Section 1-102 of the Act states that "the General Assembly finds that the health, welfare and prosperity of all Illinois citizens require the provision of adequate, efficient, reliable, environmentally safe and *least-cost* public utility services at prices which accurately reflect the long-term cost of such services and which are equitable to all citizens." 220 ILCS 51-102. The GCI also note that the General Assembly has further defined "efficiency" as "the provision of reliable energy services at the least possible cost to the citizens of the State". 220 ILCS 5/1-102(a). Further, they observe Section 8-401 to require that every public utility subject to the Act, provide service and facilities which are in all respects adequate, efficient, reliable and environmentally safe and which, consistent with these obligations, constitute the least-cost means of meeting the utility's service obligations. 220 ILCS 5/8-401.

Notably, the GCI observe that in a recent rate case order, i.e., Docket No. 04-0779, the Commission committed itself to having energy efficiency programs implemented on a statewide basis for all gas and electric utilities in time for the 2006 heating season. In making this commitment, the Commission stated:

> We feel strongly that we must move with all deliberate speed on this issue. …Given the dire projections of energy costs, time is of the essence for the deployment of energy efficiency programs on a statewide basis. Nicor, Order at 193.

Even as that hopeful goal never materialized, the GCI parties observe the Commission to have made clear its belief that EEPs are a worthwhile utility expense, by stating that:

> the Commission understands the importance and critical necessity of using energy efficiency plans as strategic tools to protect Illinois consumers and reduce their energy costs. …We believe that smart energy efficiency programs will have two effects. First, they will lower the cost of heating for the home or business participating in the program. Second, targeted correctly, they will reduce the amount of high cost natural gas that Illinois has to buy, thus reducing everyone's costs, as well. …Increased energy efficiency that decreases the individual household or business costs of natural gas and electricity and – at the same time – reduces the amount of high cost energy we have to buy – lowers prices for everyone and appears to be the premier option that Illinois has for lowering customer energy bills. Id. at 192.

The GCI recognize Staff witness Rearden to have presented the primary attack against energy efficiency programs in general, and ratepayer funding of them in particular. At the outset, GCI observe, that he would unfairly apply a higher standard of equity for energy efficiency than the Commission applies for other costs. Indeed, the GCI point out that there are numerous utility expenditures that will benefit only a limited subset of customers, despite the fact that all customers pay for the expenditure. For example, they note, when Peoples Gas or North Shore Gas extends a distribution line or provides service to a new home, the costs are spread over all customers, wherever located, although only a very limited number of customers directly benefit from the expenditure. *See, e.g.*, ELPC Ex. 2.0 at 4. According to the GCI, Staff's inequity argument is defective for another reason, i.e., it presumes that customer desire and need for EEPs is a static phenomenon. In reality, the GCI assert, customers move in and out of apartments and houses, and their need for energy efficiency assistance and initiatives is ever-changing. Moreover, GCI contend that although not all customers will benefit by directly participating in an energy efficiency program under the program, large-scale energy efficiency programs can reduce demand for natural gas, thus exerting downward pressure on gas prices. ELPC Ex. 1.0 at 5. In such an instance, they argue, all customers – even those who do not participate in energy efficiency programs – benefit from lower gas prices.

In this regard too, the GCI note, Ms. Rukis testified that Illinois is dependent on natural gas that is imported from other states and countries. PGL Ex. IR-1.0 at 4; NS Ex. 1.0 at 4. She noted that natural gas prices have increased sharply, which place not only a financial burden on residential and business customers, but also affect the ability of the State of Illinois to grow its economy and be competitive. Id. at 4-5; Id. at 4-5. She further concluded that, "Energy efficiency programs can reduce expenditures for importing natural gas supplies and assist all customers in better managing their energy use and lowering energy bills." Id. at 5; Id. at 5. She added that the Companies' proposed EEP can "reduce the total amount of therms that need to be purchased by the Companies, thus reducing the expenditures relating to the purchase of natural gas." NS-PGL Ex. IR-3.0 at 6.

ELPC witness Kubert testified that properly designed EEPs can save natural gas at a life-cycle cost of one-third the cost of purchasing and distributing that same amount of natural gas. ELPC Ex. 1.0 at 2. He noted that neighboring Midwest states, where EEPs have been implemented, have lower average residential natural gas consumption than Peoples Energy consumption rates. Id. at 2, 3. He added that despite high natural gas costs, homeowners and businesses continue to under-invest in energy efficiency for a number of reasons. Id. at 3. Ratepayer-supported EEPs help to overcome the barriers "by providing financial incentives, technical assistance and education to residential and commercial customers, retailers, distributors and contractors." Id.

According to the GCI, the record shows that Dr. Rearden's criticisms of the proposed energy efficiency program are without foundation. Indeed, the evidence indicates that the program can have significant benefits for Peoples Gas and North Shore customers and the State of Illinois. ELPC witness Kubert explained that Illinois residents spend almost $7 billion per year on natural gas. Id. And because, as Dr.

Rearden conceded, there is little, if any, natural gas produced in Illinois, Sep. 11, 2007 Tr. at 720-21, these dollars are directed out of state. In contrast, Mr. Kubert testified that energy efficiency program dollars are used in Illinois to pay contractors and vendors who implement these programs, thereby creating jobs and net economic benefits for Illinois. Id. at 4. Mr. Kubert cited an ACEEE study showing that by 2010, a moderately aggressive five-year regional energy efficiency program would result in savings of more than $1 billion for Illinois consumers, produce a net gain of nearly 6,500 jobs and an additional $220 million in net employee compensation. Id. .

While no party denies that high natural gas prices can be an incentive for conservation, GCI note that even Mr. Rearden has acknowledged that utility customers may need and benefit from the extra help an EEP provides. Tr. 722-24, 734. And, Mr. Kubert provided evidence to show that there is an underinvestment in energy efficiency as a whole in Illinois. He testified that Illinois' market penetration rate for high efficiency furnaces is around 30 percent. Tr. 1421. But, in Wisconsin, which has had gas (and electric) EEPs for many years, the market penetration for these furnaces is well in excess of 70 percent. Tr. 1421-22.

The GCI dispute Staff claims that the EEP is inefficient because high gas prices are sufficient to cause persons to invest in energy efficiency. Staff Init. Br. at 204. In their view, Staff's argument assumes a perfect market and that people have all the information and resources necessary to invest in energy efficiency programs that are in their economic self-interest. Of course, GCI contends, no such perfect world exists. Even Dr. Rearden conceded that some customers may not implement energy efficiency or conservation measures because they lack the requisite information that it is in their best interest to do so. Tr. at 708-09. And, he also admitted that "there is, at the very least, a subset of Peoples Gas and North Shore ratepayers out there who could use financial assistance in helping them make rational energy efficiency investments." Id. at 723-24. Further, the GCI observe Dr. Rearden to have added that some consumers may have sufficient funds to pay their monthly gas bills, but lack the necessary funds to make a larger outlay for energy efficiency measures even if it is in their self-interest to do so. Id.

The GCI understands Dr. Rearden to make clear that he is opposed to funding EEPs through utility rates on both a theoretical and practical basis. Tr. 726. He explained that he believes that energy efficiency programs should be financed through an income or property tax. Tr. 727; Staff Ex. 12.0 at 35. And, he stated the view that EEPs should not be provided in either Peoples' or North Shore's service territory until such time as state or federal government officials require their implementation statewide. Tr. 727-728. This shortsighted view of EEP funding should be rejected the GCI argue. In any event, they noted Mr. Kubert to explain that, because of the large customer base and the relatively small size of the EEP, a ratepayer funded program has essentially the same impact as a taxpayer funded program. ELPC Ex. 2.0 at 6.

In terms of Staff's objection to the governance of the program, the GCI consider these concerns to have no merit. ELPC witness Kubert explained in detail the structure of the governance board and why it is appropriate for a program of the size being considered in this case. ELPC Ex. 2.0 at 6-7. Peoples Gas witness Rukis described in

even more detail the operations of the governance board and the controls that will be in place to ensure effective oversight and implementation of the programs. PGL Ex. IR-1.0 at 5-11. The GCI submit that it is hard to understand Dr. Rearden's concern. Nevertheless, the City and CUB would not object if the Commission were to prescribe additional oversight.

Ms. Rukis, who has been involved since 1987 with public benefits programs, including low income, energy efficiency, distributed generation and renewables projects, testified that the Governance Board's voting procedures, which would not give any one entity the ability, acting alone, to approve or reject any matter coming before the Board, would ensure the Board's independence from the Gas Companies. The anticipated duties of the Board would be to oversee the creation and issuance of Request for Proposals and select (1) one or more Program Administrators for implementation of EEPs; (2) a Contract Administrator; and (3) a Program Evaluator. An employee of the Companies would act as Fiscal Agent and account for the funding approved by the Commission. Ms. Rukis testified that "(t)he Board would establish, in consultation with the Contract Administrator, the general Program goals and performance criteria, e.g. which types of programs should be offered to which customer segments and in what timeframe."

As explained by Ms. Rukis, the Contract Administrator would assist the Board with setting program goals, and performance criteria and budgets. This individual also would help draft the requisite Requests for Proposals and approve program spending and invoices from the Program Administrator(s) and Program Evaluator. Id. The Program Administrator(s) would be responsible for: (1) developing detailed program designs in cooperation with the Governance Board and the Contract Administrator; (2) delivery of agreed-upon programs; (3) hiring of sub-contractors for program delivery as necessary; and (4) delivery of periodic performance reports as required by the Board. Id. The Program Administrator(s) also would be responsible for preparing and delivering to the Governance Board any reports and information required by the Board. The Program Evaluator would perform periodic audits on the performance of the programs against established performance criteria, and also prepare annual reports, any other kind of reports requested, for the Governance Board. Id. at 9. The Program Evaluator would be independent of the Companies, the Contract Administrator and the Program Administrator(s). Id.

Finally, the Fiscal Agent would maintain accurate accounting records, pay invoices as approved by the Contract Administrator from the Program Administrator(s) or any subcontractors, and would help to prepare periodic financial reports. This Peoples or North Shore employee would not be involved in decisions about what to fund or how much to spend on particular programs, Ms. Rukis noted. Id. Any issues and concerns regarding disbursements associated with the programs would be directed to the Board by the Fiscal Agent for review and resolution. Id. Ms. Rukis testified that the Fiscal Agent would be charged as a Company employee with alerting the Board to any perceived anomalies, inconsistencies or other unorthodox billing detail. Tr. at 101.

Dr. Rearden's broad concern about the proposed EEP related to the oversight and administration of the program is misplaced. First, they note that his criticism that

the Program Administrator(s) are not accountable to anyone simply is not true. As explained by Mr. Kubert, the parties agreed (during the collaborative process that took place after the merger settlement) that both the Contract Administrator and the Program Administrator(s) would report to the Governance Board. In addition, the Program Evaluator would perform periodic audits on the performance of the programs against established performance criteria and also prepare annual reports for the Governance Board. Id. Again, the Program Evaluator would be independent of the gas companies, the Contract Administrator and the Program Administrator(s). Id. Moreover, the Staff liaison would be a non-voting member of the Board, thereby keeping the Commission apprised of all matters occurring with the Governance Board and its subcontractors. Id. at 6-7.

City-CUB note Dr. Rearden to be concerned with controlling overhead costs. On this point, the City and CUB agree. They assure that no party has an interest in spending limited energy efficiency funds on administrative costs. Mr. Kubert agreed with Dr. Rearden that there should be a binding constraint on the level of administrative costs and that there should be periodic reviews of the energy efficiency project overheads. ELPC Ex. 2.0 at 8. Peoples Gas-North Shore witness Rukis testified that she also agreed on these points. NS-PGL Ex. IR-3.0 at 5.

The GCI note Staff to claim that the proposed structure of the EEP does not "guarantee" "prudent expenditures." Staff Init. Br. at 202-03. Staff's argument focuses on the wrong question. The Commission should not ask whether every energy efficiency program that comes out of the EEP will be a perfect program that "guarantees" "prudent expenditures." Rather, the GCI maintain, the Commission should ask whether it is prudent to establish a program to design and implement energy efficiency programs. There is little doubt that the answer to that question is "yes."

First, Staff complains that no specific initiatives have been proposed, and the Companies cannot guarantee that the program will translate into prudent expenditures. Staff Brief at 203. However, utility ratemaking is by nature and law, a prospective process (*see, e.g.* Business and Professional People for the Public Interest v. Illinois Commerce Comm'n, 136 Ill.2d 192, 209, 555 N.E.2d 693 (1989) ("*BPI I")*; Citizens Utilities Co. v. Illinois Commerce Comm'n., 124 Ill. 2d 195, 207; 529 N.E.2d 510 (1988) that precludes the kind of before-the-fact micromanagement Staff seems to be demanding. The Commission's analysis of operating expenses, given the prospective nature of ratemaking, evaluates the kind and dollar amount of the expense being proposed, but for the most part rarely delves into the details of how the dollars are actually spent. For example, when the Commission evaluates a test year amount of office supplies, it typically does not investigate exactly how the budgeted amount is spent. Rather, the typical accounting analysis examines whether the expense itself is necessary for the provision of least-cost utility service and whether the amount requested is a reasonable, "normal" level based on historical experience. In doing so, the Commission intuitively recognizes that all businesses, gas utilities included, for example, require office supplies in order to provide utility service.

As Ms. Rukis made clear on cross-examination, the Commission would maintain authority over the EEP. The Commission has authority over the Companies' respective

rates. Tr. at 104. Through reports provided to the Board, the Commission would have the ability to review the on-going progress of the EEP. Id.

Utilities' witness Rukis testified regarding the various kinds of programs that could be a part of the EEP funding approved in this docket. She stated that one of the first things that the Governance Board should accomplish is a market potential study which would further ensure the best and wisest use of available resources by identifying the opportunities to use the funds. Tr. at 97. That being said, she noted that the most common EEP is the technology rebate, which targets individual customers or businesses to purchase or install more efficient technology than currently being utilized with lower initial purchase or installation costs. Id. at 11, 14. These could be offered to both business and residential customers. Another possible program could take the form of a door-to-door direct install of free or low cost energy efficiency measures for homes and apartments. Id. at 12. Low income programs that target selected customer groups to provide assistance to replace old, inefficient furnaces and water heaters, or install weatherization measures to homes and apartments could also be a part of the EEPs provided. Id. Another possible program, shared savings financing, could be included wherein the customer pays for the cost of the energy efficiency installation through savings from the project with a low interest loan, often at a buy-down interest rate, according to Ms. Rukis. Id. She added that other EEPs could target new customers and new loads as part of an economic development package to ensure that any new load additions to the system are as efficient as possible. Id. Other components could include efforts at market transformation that include activities that develop and provide information on available energy efficiency options and energy saving best practices through education and outreach efforts. Id. at 13.

Both Utilities' witness Rukis and ELPC witness Kubert agreed that a $7.5 million funding level for the proposed EEPs will be sufficient to implement the kinds of programs and activities described above and achieve the benefits both witnesses concur would occur given implementation of the program. Ms. Rukis noted that the aforementioned market potential study she believes would be an appropriate first step in the program would enable the Governance Board to make the best use of the $7.5 million in funding provided by Peoples/North Shore customers. PGL Ex. IR-1.0 at 16; NS Ex. IR-1.0 at 16. The periodic reports prepared by the Program Evaluator and provided to the Board will also assist in assessing the effectiveness of the programs offered. Id.

Mr. Kubert concurred that the $7.5 million, while on the extreme low end of typical EEP funding in other Midwest states, would be a conservative amount with which to begin a program. ELPC Ex. 1.0 at 6. He noted that a lesser amount "would not allow the program to develop a comprehensive portfolio of services and incentives to impact a large number of customers." Id. Some program experience may be needed before any ramp-up to a higher funding level. Id. The Peoples/North Shore proposed EEP would be open to all ratepayers, with the actual number of participants being driven by program design, marketing and outreach. Id.

b) Proposal for Rider Recovery of EEP Costs

Proposed Rider EEP would allow the Companies to collect on a monthly basis the incremental costs to develop and implement energy efficiency measures. PGL Ex. VG-1.0 at 40; NS Ex. VG-1.0 3REV at 35. In the GCI's view, however, the proposed rider would recover costs that are not volatile and thus, under Illinois law, not appropriate for rider recovery.

According to GCI, the Finkl case dealt specifically with the very type of expenditure that Peoples Gas and North Shore would recover through Rider EEP. In that case, the court addressed the Commission's approval of Rider 22, which allowed ComEd to collect through a rider costs associated with investing in energy efficiency measures. Id. The court overturned the Commission, holding that the costs to be recovered under Rider 22 were no more volatile or beyond ComEd's control than many costs that are recovered through base rates. Id. at 327. The court concluded that such costs are not appropriately recovered through a rider and also considered that Rider 22 violated the single issue ratemaking rule. Id.

It is not clear to the GCI how the Companies can distinguish Rider EEP from Rider 22. They consider the evidence in this proceeding to be even less favorable for proposed Rider EEP than the evidence regarding Rider 22. In Finkl the court explained that Rider 22 was designed to recover certain categories of costs associated with providing energy efficiency programs. Id. Arguably, those costs could fluctuate or vary depending on the magnitude of energy efficiency projects that were designed and implemented. Here, the Companies are proposing to spend a predetermined amount ($7.5 million annually) to invest in energy efficiency projects. There is no room for deviation or fluctuations. Thus, the costs that would be recovered through Rider EEP are not appropriate for rider recovery.

In defending Rider EEP, the Companies offer two reasons why Rider EEP should be approved. First, the utilities assert that Peoples Gas previously recovered energy efficiency costs through its Rider 16. PGL-NS Init. Br. at 133. The Companies neglect to mention whether that rider pre-dated the Finkl decision and why that decision is not dispositive. Next, the Utilities state that "legislation has been offered that has been offered that may lead to a statewide energy efficiency initiative. The Companies add that if they fund programs pursuant to the statewide initiative, they would not want to burden their customers with funding multiple programs. Id. The Companies' argument is not persuasive in that, as it concedes, the legislation referenced has only proposed, it has not been enacted. Moreover, it is unclear to the GCI how the proposed legislation avoids the Finkl court's holding that energy efficiency programs are not appropriate for rider recovery.

In describing how the proposed tariff Rider EEP would be administered, Company witness Grace noted: "As budget dollars may not be fully expended as the program is building awareness in the initial program years, the Company proposes to carry over up to 75%, 50% and 25% of budget dollars into the second, third and fourth program years." PGL Ex. VG-1.0 at 40-41. In the GTCI's view, however, this carryover proposal does not justify approval of Rider EEP. As noted by Mr. Brosch, differences in actual disbursements for conservation programs relative to the $7.5 million of committed

funding need not be addressed with a tariff rider. He stated that if the Commission is concerned with differences between recoveries from customers and actual expenditures by the utilities, a deferral accounting mechanism should be employed to track and reconcile differences between recovery (through base rates) and disbursements made by each utility for conservation programs. GCI Ex. MLB-1.0 at 72. Then, in future rate case proceedings, any unspent balance in the deferral account could be evaluated and recognized in the establishment of a revised ongoing recovery level within new base rates. Id. For example, if base rate recoveries total $22.5 million after three years, but only $17.5 million has been disbursed, the Commission might consider either directing larger annual disbursements for a period of time after year three or instead reduce the recovery rate embedded in a next rate case occurring at that time. If a full accounting for the economic value of base rate recovered conservation funding was desired, interest could be applied monthly to the cumulative over- or under-recovered balance in the regulatory asset or liability deferral account. Id.

The GCI note Staff to contend that deferral accounting of test year expenses is illegal under the BPI II decision. Staff Init. Br. at 221. If the Commission agrees with Staff, the GCI understand that this would require base rate treatment of the expense.

The GCI observe the Companies to propose that, if the Commission rejects rider treatment, to account for the EEP expenses through deferral accounting treatment "so long as the deferred account process was annual, as opposed to between rate cases." PGL-NS Brief at 135. The GCI argue that this approach should be rejected as unnecessarily complex and time-consuming. Mr. Brosch noted that there would be administrative cost savings to the Utilities and the Commission Staff by avoiding the creation of an additional tariff rider with periodic filings to review and reconciliation adjustments to calculate and apply. The Commission could still keep apprised of the relative success of the EEP through the filings provided by the Program Evaluator and through the Staff liaison who would sit as a non-voting member of the Governance Board. Of course, a full review of program activities and costs would also occur in periodic general rates cases where all parties with an interest in such matters can readily participate. Id.

The GCI would have the Companies' request to recover EEP costs through a Rider EEP be rejected for several reasons. First and foremost, the $7.5 million in EEP costs do not satisfy the legal criteria for permissible rider treatment. GCI witness Brosch testified that neither the size nor anticipated volatility of conservation funding expense justify a special tariff Rider for this element of the Companies' revenue requirement. He pointed out that the EEP funding obligation that would be addressed by proposed Rider EEP is a fixed $7.5 million annual amount across both utilities, an amount that is not expected to change in the foreseeable future. GCI Ex. MLB-1.0 at 72. And, Mr. Brosch stated that such a fixed expense can and should be included in the basic revenue requirement in these consolidated dockets to "ensure that the defined level of funding is made available on an ongoing basis," as suggested by Mr. Feingold. Id.

5. Commission Analysis and Conclusion

The Merits of EEP

As a condition to the merger approved in In re WPS Resources, Inc., Docket No. 06-0540, the Commission required the Utilities to propose a new ratepayer funded energy efficiency program of not less than $7.5 million per year. The Utilities fulfilled that condition by proposing Rider EEP. The Commission is highly pleased to consider and accept the EEP and it commends the concerted efforts and good work that brought it to the table.

Energy efficiency programs are socially desirable. In the recent Nicor rate case proceeding, the Commission recognized the importance and critical necessity of using energy efficiency plans as strategic tools to protect Illinois consumers and reduce their energy costs. Nicor, Order at 193, Docket 04-0779 (September 20, 2005).

As described on record, the proposed governance structure for the program should ensure independence from the Utilities and will likely result in representation of all or substantially all relevant interests. Further, the program's anticipated focus on rebates and other incentives supporting energy efficient technologies and gas saving techniques is appropriate and may encourage greater utilization of such technologies and techniques than high prices alone.

The Commission rejects Staff's arguments that the program is necessarily inequitable and inefficient. With proper independent governance and oversight, and with the selection of appropriate, cost-effective efficiency measures, the Commission believes that the proposed programs will make a significant positive contribution to the benefit of all ratepayers. Accordingly, the Commission orders the Utilities to implement the energy efficiency program as proposed. We find the structure to be fair and reasonable. The Commission additionally finds reasonable the $6.4 million that is allocated to Peoples Gas and the $1.1 million that is allocated to North Shore, as well as the portion of each amount that would be available for low income programs. And, the Commission considers Staff witness Rearden's proposal to cap administrative costs at 5% to be both reasonable and appropriate in these premises. Thus, Staff's recommendation in this instance is approved.

Rider Treatment of EEP

The Commission further considers and finds that Rider EEP costs merit rider treatment. The parties objecting to rider treatment have argued that because the Utilities have agreed to spend $7.5 million, i.e., a fixed amount, that the Utilities cannot utilize a rider to recover these expenses because since the amount is known, it cannot possibly be "unexpected, volatile or fluctuating." We disagree. The parties prominently rely on the Finkl case for this proposition. Later decisions, however, have held that nothing in Finkl limits the use of a rider to only those instances where costs are unexpected, volatile or fluctuating City of Chicago v. Illinois Commerce Commission, 281 Ill. App.3d 617 (1st Dist. 1996).

More important in our decision to adopt the Utilities' rider treatment is that the manner in which this money will be spent is far beyond the Utilities' control. A. Finkl,

250 Ill.App.3d at 327. As set out on record, the Governance Board's voting procedure ensures the independence of the board from the Utilities. Because the Utilities do not "control" how much of the $7.5 million will be spent each year, it is not appropriate for the program costs to be included in rate base. The Commission further finds that Rider EEP is a reasonable means by which the Utilities may recover the EEP costs that they incur as a result of the programs and benefit ratepayers in that they will only be charged the amount actually spent.

Also, we believe the costs are appropriately included in rate base when savings can be expected. This balancing, however, will not occur for the energy efficiency costs. We expect that any money the EEP spends on energy efficiency will decrease the Utilities revenues as customers will use less gas. Indeed, that is the whole point and objective of the EEP. Thus, in every way, these are unique costs and warrant rider treatment.

Further, knowing that the energy efficiency program will be administered by an independent board lessens our concern over the costs of administrating Rider EEP. In other words, and given the composition of this body, we expect that that any reconciliation proceedings would likely not be litigious because most, if not all interested parties, would have had a say in the efficiency program spending process.

Although we do not adopt Staff's position, several of its proposals bear consideration. Staff witness Hathhorn recommends, if the Commission adopts the Rider EEP, that: 1) an annual reconciliation procedure should be established; 2) an internal audit should be conducted; and, 3) the monthly tariff filing date should be changed. The Utilities have agreed to these changes and we adopt them as well. The annual reconciliation will ensure that ratepayers are only charged for the actual costs of the energy efficiency program prudently incurred. This is fair and just.

D. Rider UBA

The Utilities also request approval for Rider UBA to recover the gas cost-related portion of their uncollectible customer bills (also called bad debt expense). They describe Rider UBA as a monthly volumetric adjustment applied to gas the Utilities supply to customers (except in Service Classes 5 and 7). PGL-NS Init. Br. at 142. The adjustment would be computed by multiplying the uncollectible expense percentage approved in these rate proceedings by the forecasted Gas Charge revenues arising from the application of Rider 2 to the following month, then dividing by the applicable volumes for the same month, yielding the effective adjustment. Id. Any differences between billed revenues and uncollectible expenses under the Rider would be reconciled annually and amortized over a 10-month span, with the resulting adjustment added to customers' bills during that period. Id. Customers would also be responsible for (or receive the benefit of) interest on over- and under-recovered amounts. AG Init. Br. at 121. "Then, because the annual reconciliation amounts are also subject to over or under-recovery, a further true-up is required." Id.

Additionally, the Utilities would file monthly prospective reports with the Commission, detailing expected activity under Rider UBA. They would also annually audit rider performance, and file a report in February to determine the earlier discussed

reconciliation adjustment. PGL Ex. VG-1.0 at 44-45; NS Ex. VG-1.0 at 39- 40. Rider UBA will only pertain to the gas cost portion of the Utilities' bad debt expense. Non-gas cost uncollectible expense would be recovered in base rates.

The test year uncollectible gas cost expenses to be recovered through Rider UBA are $26.7 million and $1.5 million dollars for Peoples Gas and North Shore, respectively. PGL Ex. VG-1.0 at 45; NS Ex. VG-1.0 at 41. If the Commission does not approve Rider UBA, the Utilities would continue to include and recover gas cost-related bad debt through its base rates.

The Utilities maintain that "uncollectible accounts are a rising and recurring business expense" that is "uncontrollable, highly variable and unpredictable, with resulting negative financial consequences." PGL-NS Init. Br. at 141-42. They also assert that "the level of uncollectible expense on the Utilities' system is substantially greater than has historically been the case." Id. at 143. The Utilities contend further that these circumstances are the result of economic conditions…the level of gas commodity and delivery prices and the demographics of the Utilities' service territories. Id. at 141. In the Utilities' view, Rider UBA will provide the antidote to these problems by allowing steady bad debt recovery between rate cases. They stress that utility regulators in ten states have approved "bad debt ratemaking mechanisms" for gas utilities. PGL-NS Ex. RAF-1.0 at 41.

The Utilities particularly emphasize that gas costs are themselves recovered through a rider, not through base rates, precisely because of their volatility. Accordingly, and given their conviction that uncollectibles correlate with gas prices, the Utilities conclude that gas price-related bad debt should be similarly recovered via rider. PGL-NS Rep. Br. at 120, n. 32. Additionally, the Utilities support Rider UBA with the same legal arguments (concerning appropriate circumstances for rider recovery) that they have presented on behalf of their other proposed riders in these dockets.

In return, the AG, Staff and City-CUB reprise the legal arguments they presented against the Utilities' other riders. Again relying on Finkl, the AG states that "to qualify for rider treatment, expenses must be unexpected, volatile or fluctuating and significant in nature." AG Init. Br. at 114. The AG argues that Rider UBA does not satisfy the first two of those criteria because "the magnitude and volatility of these expenses do not rise to the level or degree of purchased gas costs." Id.

Further, the AG avers, gas cost-related bad debt expenses are not "substantial enough to have a material impact upon revenue requirements and the financial performance of the business between rate cases." Id. Staff echoes this argument, noting that the Utilities were able to earn their authorized rates of return when uncollectibles rose, as in 2001, when, despite a sharp rise in bad debt, Peoples Gas and North Shore earned returns on common equity of 11.14% and 12.30%. Staff Rep. Br. at 90. "Thus, if Rider UBA had been in effect during this time, both utilities would have received additional revenue boosts despite earning at or above their authorized returns." Id. at 91. Similarly, City-CUB stresses that if Rider UBA had been in place from 2-002-2006, Peoples Gas "would have collected an approximately additional $21 in pre-tax operating income and [North Shore] would have received $2.9 million." City-CUB Init. Br. at 92.

Staff also puts particular emphasis on our rejection of a proposed rider in Nicor. In that proceeding, we said that "costs, such as uncollectibles, which are a normal cost of the provision of service, do not warrant special recovery through a rider. Nicor has not met its burden of showing that these costs are of a nature that should be recovered through a rider rather than through base rates." Nicor, at 181, *quoted in* Staff Rep. Br. at 86.

Commission Conclusions

As we have stated elsewhere in this Order, rider recovery is allowed at the Commission's sound discretion. The judicial precedents cited by the parties establish no right to a rider. In a rate case, the question is whether the pertinent expenses are optimally recovered between rate proceedings through a rider, apart from the established test year cost and revenue balancing process. In prior cases, the prerequisites for rider recovery have been that the relevant costs are volatile, unpredictable and independent of utility control. Again, these are not all-or-nothing factors. Thus, for example, a modicum of cost volatility will not automatically warrant rider recovery, and a modicum of cost consistency will not necessarily preclude rider treatment.

The Utilities' principle argument on behalf of Rider VBA is the "undeniable" relationship between gas prices and bad debt[44]. This relationship provides the platform from which the Utilities would propel bad debt from rate case expense recovery to continuous rider recovery. That is, the Utilities' argument goes, because gas costs have already demonstrated the requisite characteristics for rider recovery, gas cost-related uncollectibles, which ostensibly follow gas prices, also warrant rider recovery. The Commission agrees with the proposition that there is some correlation between substantial increases[45] in gas bills and the ability of some consumers to pay those bills. However, it is one thing to say that bad debt fluctuates when gas bills fluctuate; it is another to say that bad debt moves just like gas prices (and, therefore, require the same recovery mechanism).

The Utilities' evidence does not demonstrate the degree of correlation they assert. When Peoples Gas's gas prices (PGL Ex. LTB-1.1) as well as its gas charges to customers (PGL Ex. LTB-1.2) rose dramatically in early 2001, so, too, did gas-related bad debt. PGL Ex. LTB-1.5. But when gas prices and charges dropped thereafter (and well into 2002), bad debt actually continued upward to its highest level. Id. In 2003, when gas prices jumped substantially above the 2002 level, along with an increase in gas charges to customers, bad debt dipped slightly, and the gas-related proportion of bad debt remained essentially constant. Id. Bad debt then fell during 2004 and stayed

[44] Although the Utilities mention "economic conditions" and the "demographics" of their service territories as additional causes of the unpredictability, variability and magnitude of bad debt, they offer scant evidence on these matters, PGL Ex. LTB-1.0 at 16, and do not at all demonstrate their purported connection to the Utilities' uncollectible gas cost-related expenses.

[45] Although Rider UBA also accommodates substantial uncollectibles *decreases*, the real dispute here (and the real problem, as the Utilities see it) concerns increases in bad debt. We do not presume that an entity would request a rider to avert *over*-collection of expenses.

constant in 2005 (although the proportion of gas-related bad debt increased moderately), while gas prices and charges trended sharply upward[46].

For North Shore, gas prices (NS Ex. LTB-1.1) and gas charges to customers (NS Ex. LTB-1.2) also rose steeply in early 2001, accompanied by gas-related uncollectibles. NS Ex. LTB-1.4. When gas prices and charges slumped after that (and well into 2002), North Shore's gas-related bad debt, unlike Peoples Gas's, did decrease, but not at the rate of gas prices and charges, which fell back to pre-2001 levels. Id. When gas prices and charges rose again in 2003,North Shore's bad debt spiked well beyond 2001 uncollectibles, although gas prices, and especially gas charges, did not attain the 2001 level. Id. North Shore's uncollectibles dropped in 2004, along with gas prices and charges, but in contrast to Peoples Gas's bad debt, shot up again in 2005 as gas prices and charges increased again. Id. Thus, North Shore's customer delinquencies showed a closer correlation to gas prices and charges than Peoples Gas's, but North Shore and Peoples Gas uncollectibles did not move like each other, nor did either consistently move with gas prices and charges.

The foregoing dynamics are consistent with what the Commission understands about customer behavior, at least with respect to Peoples Gas[47]. When gas bills rise, some customers will suppress their usage or install premises insulation or more efficient appliances (or turn to alternate energy sources). PGL Ex. LTB 1.0 at 11 & 16. Some will not suppress usage, but will nevertheless pay gas bills with funds intended for other purposes. Some will borrow to avoid disconnection or adverse impact to their credit. Thus, while the Utilities, under their statutory and contractual obligations, must invariably purchase gas and pass it through their purchase gas adjsutments, customers will not invariably delay or default on their gas bills in like fashion.

The evidence above additionally shows that customers adjust over time to higher bills (perhaps by resorting to the measures described above, or perhaps due to other economic factors in the service territory). Looking again at PGL Ex. LTB 1.5 (PGL-NS Rep. Br. at 120) we see that the proportion of gas-related bad debt to overall bad debt essentially holds steady, both year-to-year and over the four-year period, as does the absolute amount of gas-related bad debt. This is so despite the movement in gas prices and charges discussed above. PGL Ex. LTB-1.1 & 1.2.

Moreover, even when customers endeavor to delay or avoid paying increasing amounts due, the Utilities act to mitigate the potential revenue reduction. According to PGL-NS witness, Kallas, PGL has "been able to control its uncollectible expenses" for fiscal years 1997 through 2006 by requiring deposits from high risk customers, customer credit reporting, automated review for outstanding balances on the previous accounts of new customers, automated collections calls and disconnection prioritized by

[46] The price, gas charge and uncollectible movements described here are also reflected in PGL Ex. LK-1.2.

[47] The disparate aggregate behavior by, respectively, Peoples Gas and NS customers is not explained by the record. Because Peoples Gas has much a larger customer base (850,000 versus 158,000, PGL-NS Ex. LTB-1.0) and far higher total uncollectibles (a high of over $40 million at Peoples Gas compared to over $1.6 million for NS, PGL Ex. LTB-1.5; NS Ex. LTB-1.4), the relative impact of a few accounts may be greater for NS. Or economic differences between the service territories may be important factors.

the delinquent customer's behavior score. PGL Ex. LK-1.0 at 17. North Shore uses the same collection enhancements (NS Ex. LK-1.0 at 17) and "uncollectible expense as a percentage of applicable revenues for the test year and three preceding years…has been fairly constant over that time period," *id*. at 16, although uncollectibles rose substantially on a dollar basis in alternating years during that span. NS Ex. LK-1.2.

The salient point here is not that gas price movements have no effect on uncollectibles (they do have some effect), but that the two do not move so closely together to automatically grant rider treatment to the latter because the former has rider treatment. Moreover, through enhanced credit and collection measures, the Utilities have some appreciable capacity to constrain uncollectibles, even when gas prices move upward. Restating this in the terms of the judicial precedents and prior Commission Orders discussed previously, gas-cost related uncollectibles do not demonstrate the degree of volatility or independence from utility control that caused us to allow recovery of gas costs through riders.

Even when we consider gas-cost related bad debt on its own (that is, apart from the association of that bad debt with the Utilities' gas costs), we still do not find sufficient basis for rider recovery. The parties have briskly debated the relationship between uncollectibles and other operating expenses, with Staff and intervenors showing that uncollectibles are less volatile than other operating expenses in absolute dollars, while the Utilities show that uncollectibles are more volatile on a percentage basis[48]. The AG aptly points out that the smaller size of uncollectibles makes larger percentage movements more likely. AG Rep. Br. at 80. Additionally, on a year-over-year basis, Peoples Gas's gas cost-related bad debt has been reasonably steady (with a moderate decline) from 2001 through 2005. PGL Ex. LTB-1.5.

While North Shore has shown greater year-to-year movement in uncollectibles, Utilities' witness Kallas acknowledges that "the uncollectible provision rate (expressed both as the accrual rate as well as the effective rate (after adjustment) has operated within a fairly tight range." NS Ex. LK-1.0 at 16-17.

The Commission finds that the Utilities' fluctuations in uncollectibles are not large or frequent enough, and the incidence of bad debt is not independent enough from the Utilities' debt management practices. Again, this is not an all-or-nothing analysis. There is some fluctuation to the Utilities' uncollectibles, and there is consumer behavior beyond the Utilities' influence. But variability is a characteristic of virtually every utility cost. Despite the most perspicacious predictions, future events take their own course. Yet virtually all of those costs are still held within the test year process. Indeed, all that our rate-setting offers is an opportunity to earn a fair return, not a fixed future dollar amount.

The appropriate issue, therefore, is whether gas cost-related bad debt is unique enough to warrant an assured and continuous rider recovery of actual expense. Based on the evidence here, we conclude that it is not. The pertinent uncollectibles will be

[48] The relevant evidence appears at PGL-NS RAF-2.2, Staff Ex. 8.0 at 26 and GCI MLB-4.0 at 22-23. We note that this evidence deals with uncollectibles generally, and not gas cost-related bad debt specifically.

adequately addressed in base rates. Elsewhere in this Order, we approve significant increases, over existing rates, in gas cost-related bad debt expense – for Peoples Gas, $26.7 million, PGL Ex. VG-1.0 at 45, (versus approximately $14.5 million), and for North Shore, $1.5 million, NS EX. VG-1.0 at 41, (versus approximately $500,000). These amounts exceed gas cost-related uncollectibles in every year from 1996 through 2005, and are essentially equal to 2006 bad debt. PGL Ex. LTB-1.5; NS Ex. LTB-1.4; PGL-NS Ex's LK-1.2. That is sufficient.

Furthermore, looking forward, the evidence shows that now-existing exogenous factors described by the Utilities will tend to moderate the amount or fluctuations in the Utilities' future gas-related uncollectibles. In support of revising weather normalization methodology, the Utilities have asserted that global warming is reducing HDDs and, thereby, gas consumption. PGL Ex. LTB-1.0 at 10; NS Ex. LTB-1.0 at 10. Similarly, to justify their requested Rider VBA, the Utilities show that efficiencies and insulation, along with higher gas bills, are reducing customer usage. PGL Ex. LTB-1.0 at 11; NS Ex. LTB-1.0 at 14. Insofar as these factors constrain usage, they are also likely to limit gas-related bad debt.

Accordingly, as we did in Nicor, we reject the request to recover uncollectibles through a rider. We continue to believe that "Commodity-related uncollectibles expense should not be split from other uncollectibles expense… costs, such as uncollectibles, which are a normal cost of the provision of service, do not warrant special recovery through a rider…The gas cost portion of Nicor's uncollectibles is presently being recovered through base rates, and should continue to be recovered through base rates." Nicor, at 181.

The Commission notes that there is a consensus that the CFY customers should not be required to pay for the bad debt cost of sales customers associated with their gas costs. The Commission therefore approves the reduction in "Choices For You" charges calculated by Utilities' witness Grace. PGL-NS Ex. VG- 2.0.

E. Deferred Accounting Alternative to Certain Rider Requests

In the event the Commission rejects one or more of Riders VBA, UBA or EEP, the Utilities propose, as an alternative, to track the underlying revenues and costs in deferral accounts, for later refund or adjustment to base rates as determined on an annual basis. PGL-NS Ex. VG-2.0 at 50-51. The Utilities assert that this would not violate test year principles but would, instead, allow them to go ahead with these expenditures. Given that the Commission has approved Rider VBA and Rider EEP, but rejected Rider UBA, the Utilities' fall-back proposal would apply to the latter rider.

With respect to Rider UBA, the Utilities' argue that "normalization of uncollectible expenses is hardly unprecedented. PGL-NS Rep. Br. at 127. The Commission does not agree that the future recovery requested here is a matter of "normalization." Nor is this a matter of completing a previously approved amortization. Uncollectibles are operating expenses and, as Staff states, "recovery of operating expenses outside of the test year violates test year principles" articulated in BPI II. Staff Init. Br. at 223. Furthermore, even if the Commission could approve the requested deferred accounting

of uncollectibles, we would not exercise our discretion to do so. We believe that a reasonable quantification of the Utilities' gas-related uncollectibles has been incorporated in the rates approved by this Order. The Commission does not perceive that the Utilities' actual uncollectibles will differ appreciably from that quantification.

VIII. COST OF SERVICE

A. Overview

A cost of service study aims to find the various costs of serving all of a utility's customers and to allocate these costs to individual customer classes. Here, the Utilities have presented the Embedded Costs of Service Studies ("ECOSS") sponsored by their witness, Ronald Amen. The ECOSS for Peoples Gas is set forth in PGL Exs. RJA-1.1, 1.2 REV. - 1.4, 1.7 REV. - 1.8, 1.9 REV., and 1.10 REV and that for North Shore is set forth in NS Exs. RJA-1.1, 1.2 REV. - 1.4, 1.7 REV. - 1.8, 1.9 REV., and 1.10 REV.

The Utilities were the only parties who submitted ECOSS in these proceedings. Staff witness Luth made certain proposed adjustments to the ECOSS using the Utilities' ECOSS models. In addition, Staff the AG and City-CUB made criticisms of selective aspects of the ECOSS, but none of those parties appear to have taken issue with the Utilities' broader ECOSS methodology or approach.

In section B -1 below, addresses all of the items not in dispute.

In sections B -2 below, we examine the matters being contested. The contested ECOSS issues in this proceeding are:

(a) whether common system distribution costs should be allocated on the basis of the Coincident Peak ("CP") method proposed by the Utilities versus the Averages and Peak ("A&P") method favored by Staff;

(b) whether Account No. 904 should be classified as customer costs as proposed by the Utilities;

(c) whether S.C. No. 1 should be bifurcated into heating and non-heating customers, as proposed by the Utilities but opposed by GCI;

(d) whether Account No. 385 costs should be directly assigned, as proposed by GCI but as opposed by the Utilities;

(e) whether differentiating rates of return by class, opposed by the Utilities but proposed by City-CUB, is reasonable; and,

(f) whether the EPEC methodology proposed by the Utilities for allocating overall revenue requirement among the various customer classes is appropriate.

B. Embedded Cost of Service Study

1. Uncontested Issues

a) Functionalization of Intangible Plant Account Nos. 303.1 and 303.2

The Utilities' proposal functionalized Accounts 303.1 and 303.2 costs solely as customer - related costs. In his testimony, Staff witness Luth proposed that the Utilities functionalize those Accounts according to their relative weight of depreciable Production, Storage, Transmission, Distribution and Customer Accounts Plant. Staff Ex. 7.0 at 4. The Utilities have accepted Mr. Luth's proposal which recommends that costs in Account Nos. 303.1 and 303.2 should not be based solely on customer account costs, but should be functionalized as Customer Accounts, Distribution related and the remaining amounts spread ratably among the functions to reflect the general and administrative uses of the remaining software and systems applications. NS-PGL Ex. RJA-2.0 at 11; NS-PGL Ex. RJA-2.3.

The Commission finds Staff's final proposal, that the Utilities functionalize Accounts 303.1 and 303.2 costs as customer accounts and distribution-related, with remaining amounts to be spread ratably among the functions to reflect the general and administrative uses of the remaining software and systems applications, to be unopposed by any party. And, it is reasonable and appropriate. The Commission, therefore, approves this proposal.

b) Classification of Distribution Plant Account No. 375

The Utilities proposed the allocation of Account No. 375, Distribution Plant - Structures Improvements, as a combination of demand and customer costs. Staff witness Luth recommended that Account No. 375 be classified entirely as a demand - related cost rather than a combination of other costs, including customer costs. Staff Ex. 7.0 at 4. The Utilities have accepted the proposal of Staff witness Luth and agreed to classify Account No. 375 solely as a demand - related cost. NS-PGL RJA-2.0 at 12; NS-PGL RJA-2.3 and NS-PGL RJA-2.4.

The Commission finds Staff's final proposal, i.e., that the Utilities classify Account No. 375 entirely as a demand-related cost, which is not opposed by any party, to be reasonable and appropriate. The Commission, therefore, approves this proposal.

2. Contested Issues

a) Coincident Peak Versus Average and Peak Allocation Methods

(1) Utilities

The Utilities' preferred methodology for the allocation of system demand costs is the Coincident Peak ("CP") methodology, based on the Peak Demand Design days of their respective systems, which they believe is most appropriate in view of the specific characteristics of their respective systems and the principle of allocating costs to customers on a causal basis. For demonstrative purposes, two other options were considered by the Utilities in their ECOSS: (1) a CP method which classifies a portion of

the distribution mains as customer-related costs, and (2) an Average and Peak ("A&P") approach.

Because the Utilities' investment in their distribution systems is sized to meet peak demands so that they have the ability to meet their respective service obligations throughout the year, the Utilities believe the CP method produces the most conceptually sound and balanced outcome. A Peak Demand Design Day methodology, they explain, directly measures the gas demand requirements of the Utilities' firm service customers who create the need for the Utilities to acquire resources, build facilities and incur millions of dollars in fixed costs on an ongoing basis. PGL Ex. RJA-1.0 at 21, NS Ex. RJA-1.0 at 21. Further, the use of this methodology to allocate system demand costs is the most reasonable approach because it is related to the actual system as it was built to serve customers' specific needs. Hence, the Utilities assert, this ECOSS methodology is the best way to capture the true cost causative factors of the Utilities' operations. Finally, Utilities' witness Amen points out that this methodology is almost always utilized when designing a gas distribution system to accommodate the gas demand requirements of customers served by the system. PGL-NS Ex. RJA-1.0 at 19.

According to the Utilities, neither Mr. Luth on behalf of the Staff, nor Mr. Thomas on behalf of CUB-City, sufficiently explain why the A&P method is a more appropriate methodology for allocation of the Utilities' system demand costs. Neither witness explains how the A&P method, particularly its focus on average usage over peak usage, accurately reflects or relates to how the Utilities' systems were built. Instead, Staff provides conclusory statements that a "significant amount" of distribution costs are not affected by peak demand considerations, while Mr. Luth's support for A&P is based on his generic belief that average deliveries are a relevant consideration.

In the Utilities view, the proponents of the A&P methodology failed to address how a utility's system, if sized only to accommodate average gas demands, would be able to meet peak system demands, or why under the circumstances the Commission should deviate from its (and the industry's) norm of using the CP methodology. In the absence of detailed and persuasive analyses indicating why the A&P methodology should be adopted for either or both of their systems, the Utilities assert that the CP method should be approved because it has been supported with sound reasoning and analysis.

While the Utilities maintain that the CP method of cost allocation be applied, they observe that Staff, AG and City-CUB oppose its utilization and recommend that an Average and Peak ("A&P") method be used instead. Essentially, the parties criticized the CP method because they believe that the CP method incorrectly assumes that system costs are driven by peak demands on the system. These parties believe that a "significant amount" of distribution costs are not affected by peak demand considerations. Staff Init. Br. at 228. The Utilities observe Staff witness Luth to recommend the A&P method based upon his belief that distribution costs are affected by, but not entirely dependent on, peak demand and that some consideration be given to average deliveries. *See* Staff Ex. 7.0 at 13.

The Utilities believe that the CP method is the soundest approach to allocation of system costs. The CP method most closely matches the principle that cost causation

should follow cost responsibility. The distribution system was built to serve the peak demands of the system. Thus, a customer's peak demand on the system corresponds to the costs that have been incurred to install that capacity. Since the customer's demand on the system prompted the installation of facilities to meet that demand, it stands to reason that customers should be allocated costs in a manner that recognizes their call on the system.

The Utilities point out that the CP allocation method requires each customer to pay for the capacity that it is entitled to call upon whenever its usage necessitates it, whether on one day a year or every day of the year. To recognize average usage, as does the A&P method, the Utilities explain, is to incorporate non-cost considerations into the allocation process. This, the contend, results in diminishing cost causation responsibility and transferring cost responsibility from those customers who cause it to those customers who really bear less responsibility for the costs having been incurred.

The Utilities observe that the Commission had approved the CP method in the Utilities' last two rate cases, In re Peoples Gas Light and Coke Co., Dockets 91-0007 and 91-0586; in the two Peoples Gas rate cases prior to those, the A&P method was adopted. There is thus no settled practice in regards to the method for allocation of system costs. The trend toward promoting more direct responsibility for costs and the imperative of moving customers toward full cost responsibility as followed in the Utilities, rate design proposals, require that the same concept be applied in the system cost allocation process. The Utilities therefore urge the Commission to apply the CP method of cost allocation to the system costs in these proceedings. This is contrary to the AG's assertion that the A&P method establishes "clear precedent," AG Init. Br. at 136, The Commission has also shown a preference for the CP method and the Utilities believe that adoption of the CP method would be more consistent with the ratemaking policies employed most contemporaneously.

(2) Staff

The flaw in CP allocation, according to Staff, is its assumption that all distribution system costs are caused by additional installed capacity necessitated by natural gas deliveries on the date that natural gas volumes are greatest. Yet, as the Utilities' own cost of service witness Amen explained, not all distribution system costs vary according to increased capacity. NS Ex. RJA-1.0 at 25-26; PGL Ex. RJA-1.0, at 25. Staff contends that a significant amount of distribution system costs are not affected by the size of the distribution main, as expressed by the factor "b" in the North Shore and Peoples Gas cost equations and explanation provided by Mr. Amen. Staff rejects Mr. Amen's reason for introducing the cost equation, which is an attempt to show that distribution costs could be allocated, in part, according to customer count regardless of customer size, so that a Peoples Gas residential SC 1N customer with 9 therms of monthly usage would be allocated the same costs as a Large Volume Demand SC 4 customer with 71,933 therms of monthly usage residential SC 1N customer with 9 therms of monthly usage. Paradoxically, the cost equation provided by Mr. Amen demonstrates the inequity of fully allocating distribution system costs according to CP, even though the Utilities proposed rates based upon CP.

Staff witness Luth recommends an A&P allocation of distribution system costs. In his view, A&P is superior to CP because A&P recognizes that distribution system costs are affected by, but are not entirely dependent upon, increased installed capacity. Staff Ex. 7.0 at 13, 15. In addition to the share of deliveries on the peak date, A&P also takes into consideration average daily deliveries in allocating distribution system costs. Id. at 14. As a result, the use of the distribution system on the 364 days of the year in addition to the peak date is also considered when allocating the costs of the distribution system under A&P. Since it makes sense that distribution system costs are not entirely based upon the size of the distribution system, as demonstrated by the Utilities' witness Amen's testimony addressing the makeup of gas distribution system costs, the A&P allocation of a portion of distribution system costs according to average use throughout the year is reasonable and fair.

Staff suggests that A&P may suffer from a misnomer. A&P could probably be re-named to Peak and Average so that it is not implied that average deliveries have greater influence on the allocation of distribution system costs than the share of deliveries on the peak date. Tr. at 1482. For Peoples Gas and North Shore, A&P is weighted approximately 75 percent according to coincident peak and 25 percent according to average daily deliveries. Staff Ex. 7.0 at 14. It is clear, therefore, from the weighting of coincident peak and average daily deliveries in the A&P formula, that the effect of costs from increased installed capacity is a significant factor in an A&P allocation in addition to average daily deliveries. Thus, A&P is a more reasonable balance and measure of allocating the costs of installed mains which are unaffected by increased capacity, and costs that are affected by increased capacity, as depicted in the equations provided by Peoples Gas and North Shore witness Amen.

Over the past decade, Staff observes, the Commission has consistently found that A&P allocation of distribution system costs is preferable to a CP allocation, Tr. at 1484-85 (Luth), including: the most recent North Shore and Peoples Gas Orders (North Shore, Docket No. 95-0031, Order at 33-36 (November 8, 1995); Peoples Gas, Docket No. 95-0032 at 41-42)); Nicor Gas' most recent rate case order (Docket No. 04-0779, Order (September 20, 2005)), Illinois Power's 2004 request for increase in gas rates (Docket No. 04-0476, Order at 64-66 (May 17, 2005)), CIPS' and UE's 2002 request for increase in gas rates (Docket Nos. 03-0008 and 03-0009, Order at 98 (October 22, 2003)), Nicor Gas' 1995 request for increase in gas rates (Docket No. 95-0219, Order (April 3, 1996)); and CILCO's 1994 request for increase in gas rates (Docket No. 94-0040, Order (December 12, 1994)). For the same reasons that the Commission has found that A&P allocation is preferable to a CP allocation over the past decade, Tr. at 1484-85 (Luth), the Commission should conclude that distribution system costs should be allocated according to A&P rather than CP so that rates are based upon how the distribution system is used throughout the year, and not solely on the date of highest deliveries.

In concluding that A&P is a more appropriate method of allocating distribution system costs than CP, Staff observes that previous Commission Orders have focused on factors other than capacity, such as safety, reliability, and equipment replacement as being significant elements in the cost of the distribution system. In fact, the Orders in

the previous North Shore and Peoples Gas rate proceedings recognized those concerns in the development of the distribution system as factors that are not peak-related, and found that transmission and distribution costs should be allocated according to Staff's A&P allocation factor. Docket No. 95-0031, Order at 36-37, and Docket No. 95-0032, Order at 42-43. Staff notes that the Commission's adoption of an A&P allocation methodology has been upheld on appeal. *See* Abbott Lab. v. Illinois Commerce Comm'n., 289 Ill. App. 3d 705, 716-717 (1st Dist. 1997) (Commission's adoption of A&P is supported by substantial evidence). Thus, the Commission should once again reject the Utilities' proposed CP allocation factor because it fails to address costs that are not peak-related, and accept Staff's A&P allocation factor which recognizes and reasonably allocates transmission and distribution costs that are not only peak-related, but also affected by concerns other than design day peak.

(3) CUB-CITY

City-CUB also recommend that the Commission employ the A&P methodology. CUB-City Ex. 1.0 at 74-75. According to City-CUB, the Utilities' recommendation to use the CP method deviates from the Commission's approach in "virtually every natural gas delivery service rate case in the past ten years." Id. at 74. In this regard, they note the Commission to have concluded in the recent Nicor rate case , i.e., Docket No. 04-0779, that not all costs of the natural gas distribution system "are directly related to peak demand," and the A&P method, therefore, is a more appropriate means of allocating demand-related costs. Staff Ex. 7.0 at 13 (*citing* Nicor at 102). That principle applies equally to the Utilities. Indeed, their witness Ronald Amen conceded that the Commission had adopted the A&P methodology in Peoples Gas's previous rate case. PGL Ex. RJA-1.0 at 17.

Despite the Commission's longstanding policy of applying the A&P allocation method, the Utilities contend that the CP method best reflects cost causation on the utilities' systems. In particular, Mr. Amen asserted in his Rebuttal Testimony that, based on "the underlying engineering and cost characteristics of the distribution system," demand-related costs are incurred entirely to meet peak demands. NS-PGL Ex. RJA-2.0 at 7. In his Direct Testimony, Mr. Amen maintained that this is so because

> a peak demand design criterion is always utilized when designing a gas distribution system to accommodate the gas demand requirements of the customers served from that system, whether the investment is driven by the need to replace aging and deteriorating pipelines or for the purpose of expanding the transmission or distribution capacity to serve growing demand on the system. As Peoples Gas witness Mr. Doerk discusses (Peoples Gas Ex. ED-1.0), a utility's gas system sized only to accommodate average gas demands would be unable to accommodate system peak demands. That is, by sizing plant investment for peak period demands, the utility is assured to satisfy its service obligation throughout the year. As such, cost causation with respect to demand related costs is unrelated to average demand characteristics.

PGL Ex. RJA-1.0 at 19.

Despite Mr. Amen's professed understanding of the Utilities' operations, *see* PGL Ex. RJA-1.0 at 21, his testimony regarding the operational basis for the CP method was contradicted at the evidentiary hearing by Peoples Gas and North Shore Vice-President, Gas Operations, Edward Doerk. Mr. Doerk is the corporate officer (for both Utilities) responsible for "all facets of gas distribution utility operations including maintenance, construction, engineering, customer service, and technical training." PGL Ex. ED-1.0 at 3.

City-CUB point out that, in testimony at hearing, Mr. Doerk acknowledged that the Utilities' demand costs are not solely related to serving peak demands -- the essential premise of their objection to the Utilities' proposal to rely entirely on the system peak for allocating distribution plant costs. First, Mr. Doerk testified that the Utilities do not always immediately construct new facilities to meet increased customer demand that exceeds existing capacity. Tr. at 210-11. For example, Mr. Doerk described how increased demand from customers served through medium- or high-pressure portions of the Utilities' systems can be met by installing equipment on the customer's premises to permit service (increased throughput) at a higher pressure. Id. at 213-14. The Utilities' ability to increase capacity through system reconfigurations that allow greater throughput without constructing additional peak capacity is nowhere addressed in the Utilities' unqualified testimony or in the ECOSS submitted by Mr. Amen.

More important, City-CUB argue, is that Mr. Doerk confirmed that the Utilities' system capacity design decisions are based on *both* the demands of customers at the system peak and the load supplied to customers over periods far more inclusive than the moment of system peak. This testimony contradicts the Utilities' prepared testimony, including that of Mr. Amen, asserting categorically that the only consequential system design cost factor is peak demand. Indeed, Mr. Doerk himself stated in Direct Testimony that "Peoples Gas' system is designed . . . to meet the aggregate peak design day capacity requirements of all customers entitled to service on the peak day." PGL Ex. ED 1.0 at 4. And, Mr. Amen asserted that,

> [t]he concept of Peak Demand Allocation is premised on the notion that investment in capacity is determined by the peak load(s) of the utility. Under this methodology, demand related costs are allocated to each customer class in proportion to the demand coincident with the system peak of that customer class.

PGL Ex. RJA 1.0 at 14.

According to City-CUB, Mr. Doerk's testimony reveals that the Utilities' process for deciding whether to invest in new capacity or rely on existing capacity to meet rising demand is driven by the need to meet loads throughout the year, and not just on the design day. Thus, they assert, the Utilities' proposal to allocate distribution costs based solely on peak demand does not reflect the realities of the Utilities' operations.

Moreover, City-CUB observe, Mr. Amen agreed that the extent to which new investment, extension or installation of mains, is required to serve new customers depends on whether the utility's service territory is urban or rural. Id. at 331. It is not

clear whether in the context of this case, "for every situation" where a Peoples Gas customer can be added without installing additional footage of mains, there are "contrasting situations" where extension of mains is required, as Mr. Amen claimed. PGL Ex. RJA-1.0. This is a particularly relevant consideration for Peoples Gas because its service territory is predominantly urban. *See* PGL Ex. ED-1.0 at 3. Nor does Mr. Amen explain why, in cases where the utilities investment in mains is driven by the need to replace aging or deteriorating pipelines – a situation that Mr. Amen relegates to brief mention in his Direct Testimony, *see* PGL Ex. RJA-1.0 at 19 – what drives the level of investment is the peak load served by the main, rather than annual consumption or some other factor. These unresolved issues underscore that the Utilities have not established that the CP allocation methodology best reflects the cost causation drivers for their systems.

In addition, the Utilities have not shown that the CP allocation method reflects actual cost causation on their system. *See* City-CUB Init. Br. at 94-97. Although the Utilities continue to insist that demand-related costs are incurred entirely to meet peak demands, *see, e.g.*, NS-PGL Init. Br. at 143-44, their assertion was contradicted at the evidentiary hearing. Specifically, the Utilities' Vice-President for Gas Operations, Edward Doerk, candidly acknowledged under cross-examination that (1) the Utilities do not always immediately construct new facilities to meet increased customer demand that exceeds existing capacity, and (2) the Utilities' system capacity design decisions are based on both the demands of customers at the system peak and the load supplied to customers over periods more inclusive than just the system peak. *See* Tr. at 210-14 (Doerk); *see also* City-CUB Init. Br. at 94-97. Thus, the Utilities' proposal to allocate distribution costs based solely on peak demand does not reflect the realities of the Utilities' distribution operations.

According to City-CUB, no weight should be given to the Utilities' misleading suggestion that the A&P method assumes that the Utilities' distribution system was built entirely to meet average demand. No party disputes that the system must be able to meet peak demand. But that principle does not affect the propriety of using the A&P methodology to allocate demand-related costs. As the Utilities well know, the A&P method takes into account both average *and* peak demand in allocating distribution-related costs. *See, e.g.*, PGL Ex. RJA-1.0 at 15 (noting that the A&P methodology "often gives equivalent weight to peak demands and average demands"). In fact, Mr. Luth maintained that the "most significant factor in A&P is . . . peak demand because it represents approximately 3/4 of the allocation." Staff Ex. 19.0 at 6. Unlike the CP methodology, the A&P methodology, therefore, takes into account the relationship between investment in the distribution system and both kinds of demand that the Utilities are obliged to meet.

(4) AG

The AG explains that the ECOSS methodology proposed by Utilities' witness Amen allocates customer demand related costs based on coincident peak ("CP") demands. He testified that the CP demand estimates are based upon the engineering design-day demands that the Utilities use for planning purposes. PGL-NS Ex. RJA-1.0 at 19-21. According to City-Cub witness Thomas, this methodology results in an over-

allocation of costs to residential heating customers and should be rejected by the Commission. CUB-City Ex. 1.0 at 72.

As explained by Mr. Thomas, allocating demand costs based solely on CP demand ignores the impact that average demand has on the system. Id. Because residential customers tend to use considerably more natural gas on peak days than on average days, their share of total system demand is considerably greater during peak times than it is on average. Id. Mr. Thomas noted, however, that peak usage occurs only one day out of the year, while customers actually use and benefit from the system every day of the year. Id. at 72, 73. Accordingly, "by allocating solely on the basis of peak demand, the Utilities attribute more costs to residential space-heating customers, and fewer costs to large volume customers than those customers actually cause." Id. at 73.

While there is a relationship between CP demand on the system and the cost of service, Mr. Thomas stated that there is an equally important relationship between average demand and the cost of the system:

> Allocating costs based on CP demand assumes that Peoples and North Shore's distribution systems were designed only to meet CP demands. This methodology further assumes that each customer class would only use the system during a single day of the entire year – the day that demand is the highest. This is clearly not how customers use the distribution system. Customers depend on the distribution system to meet their demands every day, not just when they are using the most natural gas. Id.

This Commission has previously endorsed this viewpoint in several dockets, including Docket Nos. 04-0779, 04-0476, 03-0008, 03-0009, 95-0219 and 94-0040.

Moreover, the Commission has consistently adopted an average and peak ("A&P") methodology for allocating distribution costs. Id. at 74. This methodology recognizes that while the system is sized primarily to address peak demands, customers use the system throughout the entire year. Id. Mr. Thomas noted that, from a cost-causation perspective, it is appropriate to recognize that cost is driven by demand and that peak demand is very different from average demand. Id.

The AG points out that Table 7 in Mr. Thomas' Direct testimony details the level of over-allocation to residential customers and under-allocation to large volume customers that occurs under the CP methodology. CUB-City Ex. 1.0 at 75. Demand-related costs should be allocated based upon an allocation factor that weights average demands at the system load factor, with peak demands weighted at 1 – system load factor). Id. at 74, 75. This methodology is reflected in Mr. Amen's alternative schedules PGL Ex. RJA 1.8 and NS Ex. RJA-1.8.

While Mr. Amen declared in his Rebuttal testimony that the Utilities' view that demand-related costs are incurred entirely to meet peak demands is "a necessary assumption that is grounded in the underlying engineering and cost characteristics of the distribution system," PGL-NS Ex. RJA-2.0 at 7, Mr. Thomas countered that this view

is belied by the fact that the cost of distribution facilities are also a function of usage. CUB-City Ex. 2.0 at 28. Because customers rely on the distribution system to be available every time they desire gas (not just at peak demand), this requirement also drives costs. Mr. Thomas explained that "it is much more accurate to say that the system is designed and installed to meet year-round demand, but should be sized to meet peak demand." Id.

(5) Commission Analysis and Conclusion

The issue is whether common system distribution costs should be allocated on the basis of the CP method or the A&P methodology.

The Utilities preferred methodology is CP because, in their view, it most appropriately takes account of the specific systems that are sized to meet peak demands and, in doing so, adheres to the principle of allocating costs on a causal basis. Staff, the AG, and City-CUB, all maintain that an A&P method is more balanced because it weights 75% according to coincident peak and 25% according to average deliveries.

In every situation where it is reasonable to do so, the Commission will consider its own past practice in resolving an issue. Staff stipulates that over the past decade, the Commission has consistently found the A&P allocation of distribution system costs to be preferable to a CP allocation. There is nothing to persuade us differently in this Instance. In other words, the Utilities have not overcome the Commission-established and long-standing tradition of A&P methodology for allocating distribution costs.

b) Classification of Uncollectible Account Expenses Account No. 904

(1) The Utilities

In the ECOSS, the Utilities classified Account No. 904 costs, Uncollectible Account Expenses, as customer costs. They note, however, that Staff witness Luth would have Account No. 904 expenses be classified as a combination of customer costs, demand costs, and commodity costs, including gas costs. Staff Ex. 7.0. Mr. Luth would also apportion the uncollectible expense in each customer class to the respective demand, customer and commodity classifications by the relative weight or percentage of revenue requirement from each customer class resulting from demand costs, commodity costs, customer costs and gas costs.

The Utilities contend that their proposal is more appropriate because Account No. 904 costs are a function of customers' unpaid bills and not the underlying components of those bills. As such, they assert, the uncollectible expenses have no bearing on whether the expenses are fixed or variable charges or the specific costs which may be covered by those bills. Residential customers do not even receive fully allocated costs. NS-PGL Ex. RJA-2.0 at 13. Hence, any attempt to match the recovery of uncollectible expenses to specific charges is misplaced because the amount of uncollectible expense (or any other expense) that is recovered by the customer demand and distribution charges of a particular service schedule is uncertain because the revenues produced by any customer class are not necessarily equal to their fully

allocated costs. Furthermore, the Utilities argue, the customer, demand and commodity related costs for a particular customer class are not translated directly into similar rate components in the Utilities' rate schedules. NS-PGL Ex. RJA-3.0 at 6. Mr. Luth's proposal regarding Account No. 904 should be rejected because he seeks to inappropriately use rate design as justification for cost classification and allocation in an ECOSS. This is polar opposite to what is conventionally sought to be achieved by an ECOSS. An ECOSS drives rate design and rate design should never drive the cost of service.

(2) Staff

Staff notes that the Utilities' cost of service study witness has recognized that costs, not recovered from uncollectible accounts, are a blend of customer costs billed through the customer charge, and unrecovered demand and distribution costs billed through variable usage and demand charges. Tr. at 343, 346-47 (Amen).

Staff illustrates that if a customer with a customer charge of $19.00 and usage charges of $15.00 does not pay his bill, an amount totaling $34.00 becomes uncollectible. And, if another customer with the same $19.00 customer charge but $400.00 in usage charges does not pay her bill, $419.00 becomes uncollectible. Tr. at 346-47. According to Staff, the customer who does not pay her $419.00 bill adds a far greater amount to uncollectible expense (because her bill included $400.00 in usage charges compared to the $34.00 uncollectible account that had only $15.00 in usage charges).

From this, Staff derives that uncollectible accounts expense are affected by the charges on a customer's bill that become uncollectible. In Staff's view, since a portion of a customer's account that becomes uncollectible is comprised of a fixed customer charge, it is reasonable to recover a portion of uncollectible accounts expense through the customer charge. And, since another portion of a customer's account that becomes uncollectible is comprised of variable usage and possibly demand charges, it is similarly reasonable and appropriate, to recover a portion of uncollectible accounts expense through variable usage and demand charges. Nonetheless, and for reasons that do not make sense to Staff, the Utilities claim that uncollectible expenses have no bearing on whether the expenses are fixed or variable charges or the specific costs which may be covered by those bills. NS-PGL Init. Br. at 145.

According to Staff, the Utilities are wrong in claiming that Mr. Luth seeks to use rate design as justification for cost classification and allocation in an ECOSS, because he is not seeking to change the results of the ECOSS to change how rates are designed. Staff explains that the expense of uncollectible accounts is a function of, and affected by, the underlying charges on a customer's bill that is unpaid. As such, Staff asserts, uncollectible accounts should not be considered solely on customer cost because these are not the only costs that are not paid on an uncollectible account. Therefore, uncollectible accounts expense should be allocated according to the origin of the charges because the costs included in all charges on an uncollectible account are not recovered as a result of bills that are not paid. Staff asks the Commission to conclude that the amount of uncollectible accounts expense is caused by the charges that appear on the bills that become unpaid and uncollectible, making it appropriate to

allocate uncollectible accounts expense according to the blend of costs that result in the charges on bills of uncollectible customer accounts.

(3) Commission Analysis and Conclusion

The issue here is whether Account No. 904 should be classified as customer costs as the Utilities have proposed.

Having studied the positions at hand, the Commission accepts Staff witness Luth's proposal that Account No. 904 expenses should be classified as a combination of customer costs, demand costs, and commodity costs including gas costs. The Commission further accepts Mr. Luth's proposal to apportion the uncollectible expense in each customer class to the respective demand, customer and commodity classifications by the relative weight or percentage of revenue requirement from each customer class resulting from various categories of costs. The analysis provided by Staff in this instance is clear, thorough and highly persuasive.

Therefore, the Commission approves, as reasonable and appropriate, Staff's classification of expenses recorded in Account No. 904, Uncollectible Account Expenses.

c) Allocation of Costs to S.C. No. 1H and S.C. No. 1N

(1) North Shore / Peoples Gas

The Utilities' propose to bifurcate S.C. No. 1 into heating (S.C. No. 1H) and non-heating (S.C. No. 1N) categories. According to the Utilities, doing so will allow for better alignment of costs and revenue recovery, and also provide more equity between and within rate classes, by setting rates closer to the costs of service. PGL Ex. VG-1.0 REV at 11, NS Ex. VG-1.0 3REV at 9. The Utilities' ECOSS shows a significant difference in fixed costs for heating and non-heating customers. They contend that fixed costs for heating customers are twice as high as those of non-heating customers. A single service classification for heating and non-heating customers, the Utilities argue, would slow the movement of non-heating customers toward cost-based service rates. PGL Ex. VG-1.0 REV at 1; NS Ex. VG-1.0 2Rev. at 9.

The Utilities contend that they have properly classified customers into heating and non-heating designation. The Utilities further explain that they have attached such designations to their small residential accounts for at least twenty years. These designations, they note, were made on the basis of information provided by the customers at the time service commenced or in follow-up calls from the Utilities, through service inspections, and further through billing department analyses of customer account usage.

The Utilities maintain that they have provided evidence showing that 97% of Peoples Gas' and 91% of North Shore's S.C. 1N monthly bills are for 50 therms or less, which supports the assumption that S.C. 1N customers generally use less than 500 annual therms, while heating customers would be expected to use more than 500 therms a year. Furthermore, the Utilities maintain that they have demonstrated that usage is one of a few important factors that would be considered to ensure that customers are properly classified. NS-PGL Ex. VG-2.0 at 32.

(2) Staff

Staff witness Luth recommended that North Shore and Peoples Gas SC 1N and SC 1H customers have the opportunity to be billed for a minimum of 12 months under SC 1N and SC 1H, depending upon how the customer believes that gas service will be used over the next heating season. NS-PGL Init. Br. at 149 and Staff Ex. 19.0 at 9-11. If the Utilities cannot administer and advise SC 1N and SC 1H customers of a potential choice between billing under either SC 1N or SC 1H, Staff would have the Utilities abandon their proposal. Staff Ex. 19.0 at 11. Cost of service for SC 1N and SC 1H should be combined, with rates based upon the combined cost of service with the lower customer charge with Rider UBA that is between the proposed SC 1N and SC 1H customer charges, as shown in the surrebuttal testimony of North Shore and Peoples Gas witness Grace. Staff Init. Br. at 236 (*referencing* Customer Charge with Rider UBA in Exhibit VG 3.1, columns [B] and [D], line 9). Staff does not recommend that the Commission authorize Rider UBA, but it does not make sense that a customer charge is lower with Rider UBA because the proposed Rider UBA would be a variable charge based upon therms delivered. Staff Init. Br. at 236.

Staff explains that its recommendations attempt to address significant bill impacts on what probably would be a small number of SC 1N customers. Nonetheless, Staff maintains, relatively high-use SC 1N customers should not pay more for the same therms as a SC 1H customer simply because the SC 1N customer does not use natural gas for space heat. Even if 97 percent of potential Peoples Gas SC 1N bills and 91 percent of potential North Shore SC 1N bills would be for 50 therms or less, 3 percent and 9 percent of those respective Peoples Gas and North Shore SC 1N bills would be for more than 50 therms. With rate differentials on deliveries over 50 therms of 38.679¢ per therm at Peoples Gas and 27.406¢ per therm at North Shore under SC 1N and SC 1H rates proposed by the Utilities (rate tables in Staff IB at 237-239), therms delivered under SC 1N become far more expensive than therms delivered under SC 1H in short order. For 3 percent of potential Peoples Gas SC 1N customers and 9 percent of potential North Shore SC 1N customers, Staff believes that the billing consequences could be significant. Staff's recommendation is that the basis for differentiating SC 1N and SC 1H customers should be usage, with choice available to customers, so as to prevent unfair bill impacts.

Since the Company apparently cannot administer providing notice of choice, and guidance for that choice, to SC 1N and SC 1H customers, Staff believes that SC 1N and SC 1H cost of service should be combined. Rates for a single SC 1 residential customer class should be based upon a $15.79 customer charge at Peoples Gas and $14.69 customer charge at North Shore, with usage charges recovering the balance of the combined SC 1 costs from customers at each respective company at the percentage of revenues and cost of service recommended by Staff.

(3) City-CUB

City-CUB question the need for the Utilities' bifurcation proposal. They note GCI witness Glahn explained that, according to the Utilities' own work papers, the per-unit cost of regulators for non-heating customers is less than a third of the cost for heating customers, and that the per-unit cost of services for non-heating customers is

approximately one-third the cost for heating customers. GCI Ex. 3.0 REV., at 16-17. And, Mr. Glahn added that this alleged difference seems implausible, because the cost of installing services presumably would depend largely on labor and construction costs that "should vary little by the size of the pipe, at the sizes typically used for residential customers." Id. at 17.

City-CUB observe Mr. Glahn to have questioned whether the utility would dig up an old service and replace it with a larger one every time a non-heating customer decides to install a gas furnace and become a heating customer, or instead simply install from the beginning services that would accommodate a range of end uses. Id. at 7-11; *see also* Tr. at 210-11 (where Mr. Doerk states that: "[o]n a case-by-case basis . . . it is possible" that a residential customer could double consumption without requiring a larger service pipe). In City-CUB's view, the Utilities have not satisfactorily explained why there is ostensibly such a large disparity in the cost of services for heating and non-heating customers in S.C. 1.

City-CUB note Mr. Amen stated that the magnitude of the asserted cost difference is attributable to the "occurrence of multiple S.C. No. 1 non-heating customers served by shared gas lines" and the fact that nearly half of Peoples Gas's residential heating customers are served by a separate service line. PGL-NS Ex. RJA-2.0 at 15; PGL-NS Init. Br. at 147. Yet, in her testimony, Ms. Grace stated that S.C. No. 1 includes only dwellings with two or fewer units. Tr. at 959. If this is the case, City-CUB considers Mr. Amen's explanation for the cost of service differential between S.C. 1 heating and non-heating customers to be implausible. It seems highly unlikely, they argue, that service costs vary significantly, i.e., by a 3-to-1 ratio, as calculated by Mr. Glahn, according to whether the service is used by one customer or is shared by two customers.

City-CUB witness Mr. Amen testified that, a "relatively prevalent practice" in the gas distribution industry is to have two single-family dwellings share a single service. In such cases, he added, "the service line has enough capacity, generally speaking, that it doesn't require a larger service than it otherwise would to service a single customer," depending on the pressure system to which the service is connected. Tr. at 321. Further, City-CUB observe Ms. Grace's account that, "[c]ertain non-heating customers may consume larger quantities [of gas] than heating customers in a given month due to personal preferences such as cooking, water heating or clothes drying as well as the efficiency of appliances used for such activities." NS-PGL Ex. VG-3.0REV. at 8. The ECOSS results notwithstanding, City-CUB observe that the Utilities have never asserted that larger services must be installed to serve such non-heating customers even though their loads may exceed those of heating customers. Nor is it clear to City-CUB, whether the Utilities' claim that "[a]s a group, heating customers place a significantly higher peak load on the system than do non-heating customers" refers to all heating and non-heating customers or just heating and non-heating customers in S.C. 1. PGL-NS Init. Br. at 148.

According to City-CUB, the Utilities can not expect the Commission to approve the bifurcation of S.C. 1 into heating and non-heating sub-classes based on a questionable cost of service differential that may or may not apply to heating and non-

heating customers *in S.C. 1*. They assert that the Utilities have failed to demonstrate that the ostensibly significant difference in the cost to serve S.C. 1 customers is due to a heating/non-heating distinction rather than to the single/multiple family factor that Mr. Glahn identified.

As to the Utilities' contention that S.C. 1H customers would pay lower rates under bifurcation than under Mr. Glahn's recommended rates (PGL-NS Init. Br. at 148), City-CUB believe that this claim fails to consider the potentially significant impact on such customers' usage of energy efficiency programs, particularly those targeted at low-income customers. *See* GCI Ex. 6.0 REV. at 13.

Further, City-CUB argue, the Utilities have not demonstrated that bifurcation would mitigate any subsidy running between heating customers and non-heating customers. They point out that the Utilities appear to agree that, to the extent there currently is an intra-class subsidy within S.C. 1, it is from heating to non-heating customers. PGL-NS Init. Br. at 148-49; GCI Ex. 3.0 REV. at 22-23. This conclusion is based on Peoples Gas's class revenue/embedded cost comparison, PGL Ex. VG-1.3 at 2, which shows that at current rates, non-heating customers pay 62.55 percent of their proposed cost of service, while heating customers pay 70.93 percent of their proposed cost of service – a gap of 8.38 percent. GCI Ex. 3.0 REV. at 22-23. Although the Utilities' proposed rate increase allocation would move both groups closer to their respective costs of service, City-CUB contend that this allocation would narrow the gap in the percentages of cost of service paid by S.C. 1N and 1H customers by a negligible amount – from 8.38 percent to 8.3 percent. Thus, to the extent heating customers are subsidizing non-heating customers under current rates (when compared with each sub-class's proposed cost of service), City-CUB argue that bifurcation would not eliminate or meaningfully reduce that subsidy – one of the Utilities' stated goals in proposing bifurcation. *See* PGL Ex. VG-1.0, 2 REV. at 11; NS Ex. VG-1.0, 3 REV. at 9.

Further, City-CUB argue, the Utilities' claim that bifurcation "does not result in higher rate increases for heating customers," is irrelevant to the merits of bifurcation. PGL-NS Init. Br. at 149.

According to City-CUB, the Utilities have failed to show that bifurcation of S.C. 1 is warranted. The evidence of record, they contend, establishes neither that the alleged disparity in the cost of serving S.C. 1 heating and non-heating customers is significant, nor that bifurcation would mitigate any intra-class subsidy within S.C. 1. Accordingly, they argue, the Utilities' bifurcation proposal should be rejected.

(4) AG

The AG notes that the Utilities proposed the bifurcation because it would allow each company to meet its first two objectives, which are to (1) better align costs and revenue recovery and (2) provide more equity between and within rate classes. PGL Ex. VG-1.0 at 11; NS Ex. VG-1.0 at 9. But, the AG argues, Mr. Glahn testified that the proposed bifurcation results in significantly higher rate increases for heating customers. GCI Ex. 3.0 at 17. The AG explains this to mean that the larger increase is imposed on customers with less flexibility in peak winter consumption and, because their usage is not limited to cooking appliances, less ability to substitute energy sources. And, the AG

maintains, the proposed bifurcation also shifts the cost allocation subsidy, so that under the Utilities' proposal, heating customers will be subsidizing non-heating customers. Id. at 22. Before application of the proposed rate increase, the AG points out, non-heating customers pay 62.55 percent of the cost of service for this group, and heating customers pay 70.93 percent of their costs. Id. Because the AG believes that the Utilities' proposed rate changes would only narrow the gap in terms of cost allocation by less than a percentage point, "the only thing accomplished by the proposed bifurcation is to saddle heating customers with a much larger increase in customer charges." Id. at 23.

According to the AG, Staff witness Michael Luth likewise expressed concern regarding the proposed residential class bifurcation. In rebuttal testimony, he proposed that residential non-heating customers be permitted to choose either S.C.1N or S.C.1H during the next 12 months on their bills due during the non-heating months of June 15th through October 15th, out of concern that non-heating customer bills could at some point exceed heating customer bills. Staff Ex. 19.0 at 9-10.

In rebuttal testimony, Utilities' witness Amen opined that Mr. Glahn "failed to account for the occurrence of multiple S.C. No. 1 non-heating customers served by shared gas service lines." PGL-NS Ex. RJA-2.0 at 15. He stated that 97 percent of Peoples Gas non-heating residential customers share a gas service line while almost half (47%) of the residential heating customers are served by a separate, dedicated line. Id. Thus, the principal driver for the bifurcation is not heating vs. non-heating, but rather multi-family vs. single family or single meter vs. separately metered. GCI Ex. 6.0 at 4.

In rebuttal testimony, the AG observes Mr. Glahn to have acknowledged this new distinction, observing that it "goes a long way to explain the cost differential between the two groups." Id. He observed, however, that the cost-causation information in this observation regarding multiple units is largely lost in the Utilities' artificial distinction between "heating" and "non-heating". Id. Thus, he concluded, and the AG agrees, that the heating/non-heating bifurcation should still be rejected in this case, and after the Utilities "have properly accounted for the multi-family phenomenon that actually drives the cost of service differences of S.C.1 subgroups", the Utilities should propose a new cost of service study in a future rate case that supports a more appropriate bifurcation. Id.

The AG maintains that the Utilities' proposed bifurcation of the residential class should be rejected.

(5) North Shore / Peoples Gas Response

The Utilities contend that dividing S.C. No. 1 customers into multi-family and single family classes, as proposed by GCI witness Glahn, would do nothing to help recognition of the fact that heating customers place a significantly higher peak load on the system than do non-heating customers. NS-PGL Ex. RJA-3.0 at 8.

It is also undisputed, the Utilities observe, that under the current rate structures, an intra-class subsidy from the Utilities' heating customers to non-heating customers exists, and that the single rate for heating and non-heating customers slows the movement of non-heating customers' rates toward cost. PGL Ex. VG-1.0 REV at 11,

NS Ex. VG-1.0 2REV. at 9. According to the Utilities, they have also demonstrated that fixed costs for heating customers are twice as high as those for non-heating customers, and that such a significant difference would result in the recovery of fixed costs through fixed charges under a single rate which could overburden small non-heating customers. PGL Ex. VG-1.0 REV at 11; NS Ex. VG-1.0 3REV at 9.

Even Mr. Glahn, the Utilities observe, admits to only having problems with the implementation of the bifurcation, and he further admits that the Utilities' proposed heating and non-heating distinction is "common in the industry". GCI Ex. 3.0 REV., at 16. The Utilities understand Mr. Glahn's perceived implementation problems to be that: (1) the proportion of costs assigned to heating customers appears "implausibly" high; (2) rates disproportionately impact low and fixed income customers; (3) there will be little shift in the subsidy of non-heating customers by heating customers under the Utilities' proposal. Id. at 16. Each of these issues, they assert, is without support in the record.

First, Utilities note, Mr. Glahn's assertion that the cost differentials between S.C. No. 1 and S.C. No. 1N are "implausibly high" is irrelevant and, in any event, is based upon flawed analysis. His "average per customer" calculations for service plant, the Utilities point out, ignore that multiple residential heating customers are served by shared gas service lines - a predominant circumstance on the Peoples Gas system. NS-PGL Ex. RJA-2.0 at 15. Peoples Gas' ECOSS properly accounts for the sharing of service lines by multiple customers. Id. at 16. According to the Utilities, Mr. Glahn also inaccurately, and without support, generalizes that multi-family units spread fixed costs over a larger customer base driving down costs per customer. GCI Ex. 6.0 REV at 4. For their part, the Utilities assert, the bifurcation into heating and non-heating classes appropriately recognizes customers' respective load characteristics by reflecting the single largest component of distribution plant which drives cost responsibility, *i.e.*, the cost of mains. The capacity cost of mains is driven by peak load and, as a group, heating customers place a significantly higher peak load on the system than do non-heating customers. Dividing S.C. No. 1 customers into multi-family and single family classes would not assist in the recognition of this important cost causation factor. NS-PGL Ex. RJA-3.0 at 8.

Second, the Utilities consider Mr. Glahn's criticism, that the 1N/1H bifurcation disproportionately impacts low income customers (GCI Ex. 3.0 REV, 17-18) to be unavailing. It was established by Ms. Grace, the Utilities point out, that the rates under the Utilities' bifurcation proposal would be lower than those proposed by Mr. Glahn, and particularly during the winter. NS-PGL Ex. VG-2.0 at 33.

Finally, Utilities contend, the assertion that bifurcation is not needed because there is no shift in the subsidy of non-heating customers by heating customers also lacks merit. A primary purpose of bifurcation, Utilities assert, is to better align costs and revenue recovery. PGL Ex. VG-1.0 REV at 11; NS Ex. VG-1.0 3REV at 9. Because the fixed costs for S.C. No. 1H are twice as high as the fixed costs for S.C. No. 1N, the current single service rate structure does not appropriate align costs with their causal factors and thus smaller use, non-heating customers are overburdened. Id.; Id. at 9-10. The Utilities observe Mr. Glahn to support his assertion by comparing the difference between the cost recovery percentages of S.C. No. 1 and S.C. No. 1N before and after

the proposed rate increase (8.38% and 8.3%, respectively), and then, on this basis, concluding that since the differences between the percentages remain basically the same before and after the proposed rate increase, bifurcation of S.C. No. 1 is unwarranted. GCI Ex. 3.0 REV at 23. The Utilities' view this simplistic comparison to prove nothing with respect to the appropriateness of bifurcation, nor does it serve to address or refute Ms. Grace's testimony establishing that the proposed bifurcation does not by itself result in higher rate increases for heating customers, contrary to Mr. Glahn's assertion. NS-PGL Ex. VG-2.0 at 33-34.

While Staff witness Luth did not oppose the bifurcations, the Utilities recognize that he did set out a proposal to determine customers' eligibility for S.C. Nos. 1N and 1H. His initial proposal was problematic, they claim. Id. at 26-31. And, a substitute proposal did not eliminate the problems and only introduce new problems. NS-PGL Ex. VG-3.0 at 7-9. According to the Utilities, Mr. Luth has not demonstrated that his proposals are warranted, practical or workable.

(6) Commission Analysis and Conclusion

The issue at hand is whether S.C. No. 1 should be bifurcated into heating and non-heating customers. While the Utilities urge bifurcation, the GCI parties oppose it, and Staff appears to have an implementation issue. This situation requires the Commission to apply its best and considered judgment on the evidence and arguments presented.

The Commission is not persuaded by the opposition or the recommendations of GCI witness Glahn. Notably, he acknowledges that the heating and non-heating distinction is "common in the industry." Yet, he would dismiss the bifurcation proposal here on little more than his belief that the cost differentials between S.C. No. 1H and S.C. No. 1N are too high. We consider the Utilities to have effectively challenged Mr. Glahn's analysis and shown to the Commission that it has no bearing on whether the Utilities proposed bifurcation is appropriate, and further that his suggestion of a multi-family and single family bifurcation is unsupported. We further note that Mr. Glahn's average per customer calculations for service plant ignore the occurrence of multiple S.C. No. 1N customers served by shared gas service lines, while the Utilities' ECOSS properly account for the sharing of service lines by multiple customers.

In our view, the Utilities' bifurcation of S.C. No. 1 into heating and non-heating classes appropriately recognizes those customers' respective load characteristics by reflecting the single largest component of distribution plant which drives cost responsibility, i.e., the cost of mains. The Commission is unconvinced that dividing S.C. No. 1 customers into multi-family versus single family classes, as proposed by Mr. Glahn, would help to recognize cost causation as well as does the Utilities' heating and non-heating classification proposal.

Mr. Glahn's criticism that the 1N/1H bifurcation disproportionately impacts low income customers is unconvincing. We see evidence from the Utilities to show that their bifurcation proposal will actually result in lower rates, especially in the winter. This we cannot disregard. Finally, we observe that both the Utilities and Mr. Glahn agree that a subsidy from heating to non-heating exists. While Mr. Glahn appears to complain

that there is lack of significant change in nominal percentages before and after the proposed bifurcation, we are not convinced that that this ground is sufficient enough to reject the Utilities' S.C. No. 1 bifurcation proposal given all of the other justifications for the proposal on record.

While the Commission is not persuaded that bifurcation is inappropriate simply because of the implementation issues raised, we are concerned about the possible rate impacts identified by the Staff. In particular, we observe that there could be a small number of non-heating customers who have relatively high usage in some months, and thus, would pay more than a heating customer with the same usage. The Commission, finding such an account on the record, is concerned about that result. Accordingly, and on the entirety of the evidence and the arguments presented, the Commission rejects the Utilities' proposed bifurcation in these premises.

d) Allocation of Distribution Plant Account No. 385

(1) Peoples Gas

Peoples Gas allocated the majority of Account No. 385 costs, which represent industrial measuring and regulating station equipment expense, to S.C. No. 2.

(2) CUB-CITY

With respect to the costs recorded in FERC Account No. 385 – Industrial Metering and Regulating Station Equipment, City-CUB observe that the Utilities have directly assigned the costs to S.C. 2 and 4. Because such costs can be attributed to individual customers, they assert that, as a matter of fairness, this should be done..

City-CUB note Mr. Amen to have agreed that direct assignment of costs to the individual cost causers is preferable to allocation based on secondary factors. Tr. at 324. And, they observe, it is undisputed that: (a) the Utilities can track FERC Account No. 385 costs to individual customers; (b) customers that cause the Utilities to incur costs recorded in Account No. 385 may migrate from one rate classification to another; and (c) the number of such customers is small. NS-PGL Ex. RJA-2.0 at 17-18.; *see also* Tr. at 324-25 (Amen).

Based on these considerations, City-CUB point out, GCI witness Glahn recommended that the Utilities impose a special "facilities charge" or "metering surcharge" on the individual customers causing the costs in Account No. 385, regardless of the rate classifications to which the customers belong. GCI Ex. 6.0 REV. at 5. Direct assignment to individual customers, City-CUB argue, would ensure that the Utilities recover Account No. 385 costs entirely from the actual cost causers – not the cost causers as well as other non-cost causers who happen to be in the same customer class as the cost causers. Although Mr. Amen claimed at the evidentiary hearing that Account No. 385 costs were directly assigned, City-CUB observe that he really meant they were assigned to entire customer classes (S.C. 2 and 4, *see* PGL Ex. RJA-1.0 at 29) and not to the individual cost causers within those classes. Tr. at 324.

City-CUB note Mr. Glahn to have discussed a particularly blatant example of the unfairness of assigning Account No. 385 costs to entire customer classes rather than individual customers. This, they explain, arose out of the rebuttal testimony of Mr. Amen wherein he identified a situation where:

> [A] current S.C. No. 2 customer, an electric power plant with test year consumption in excess of 500,000 therms, which had previously taken service under S.C. No. 7 (Contract Service). This customer alone represents $136,000 (over one-third) of the $373,000 recorded in Account No. 385. Thus, large industrial customers can and do receive service under S.C. No. 2, which may require significant investment in metering and regulator facilities. PGL Ex. RJA-2.0 at 17-18.

As Mr. Glahn observed, general service customers such as those in S.C. 2 also "typically include small businesses, such as dry cleaners, fast food franchises, small offices and the like," GCI Ex. 3.0 REV. at 25. Under the Utilities' proposed assignment of Account No. 385 plant investments, customers in S.C. 2 – including small businesses – would pay for special industrial equipment needed to serve an electric power plant or similarly large customers, not because they required such equipment, but because they are served under the same rate classification as the customers that do. It is patently unfair, the City-CUB argue, to charge Account 385 costs to any customers other than the large customer needing the special equipment associated with Account 385 costs.

Nothing in Mr. Amen's testimony, City-CUB assert, serves to undermine Mr. Glahn's recommendation. In their view, Mr. Amen's opinion, *see* NS-PGL Ex. RJA-3.0 at 10-11, that direct assignment of Account No. 385 investments raises the question of whether other customer-specific costs should be directly assigned to individual customers – a result that Mr. Amen characterizes as impractical – does not defeat the reasons that Account No. 385 can and should be assigned to the customers causing such costs. Such other customer-specific costs are not at issue here, City-CUB argue. And, even if Mr. Amen is correct that removing gross facilities costs in Account 385 would have a "negligible impact" on S.C. 2 customer charges, *id.* at 11, City-CUB maintain that the cost impact of following sound cost allocation principles is not a basis for ignoring them. Here, they contend, the applicable principle is that costs that can be directly assigned to particular customers should be so assigned – an approach that, according to Mr. Amen, cost analysts seek to maximize. PGL Ex. RJA-1.0 at 12. That doing so with respect to Account No. 385 investments incurred to serve one particular customer ostensibly would have little impact on customer charges for S.C. 2 does not excuse the Utilities' failure in this instance to follow the overriding preference for direct assignment of costs.

City-CUB would not have the Commission be misled by Mr. Amen's suggestion at the evidentiary hearing that charging Account No. 385 costs to the cost causer(s) within, but not other members of, that customer's service would amount to "taking a single customer out of" the applicable service classification. Tr. at 326. According to the City-CUB, the Utilities do charge individual customers in various customer classes the customer-specific costs that other customers in those classes do not pay. For example, under the Utilities' Rider 4, Extension of Mains, when a customer requests

that the utilities install a main in a different location than is required to provide service, the individual customer bears the incremental cost of meeting that customer's preferences. *See* PGL Ex. VG-1.0 3REV. at 36. And, as NS-PGL witness Valerie Grace agreed on cross-examination, recovering customer-specific costs from an individual cost causer – but not from other customers in the same customer class – does not affect the customer's membership in a service classification. *See* Tr. at 967-68.

According to City-CUB, the Utilities offer no sound reason for refusing, with respect to Account No. 385 plant, to implement its practice of directly assigning costs to the cost causers. Because Account No. 385 costs can be tracked to particular customers, they assert that such costs should be charged to these customers, and only to these customers.

(3) AG

The AG explains that the Utilities' Distribution Plant Account No. 385 is described by the Federal Energy Regulatory Commission ("FERC") as industrial measuring and regulating station equipment serving large industrial customers. GCI Ex. 3.0 at 24. The testimony of Mr. Amen, the AG observes, indicates that the Utilities can track these costs to individual customers, including an electric power plant that represents one-third of the cost amount recorded in Account No. 385. And, the small number of customers that trigger these costs may move from one rate classification to another. PGL-NS Ex. RJA 1.0 at 17. Despite these facts, the AG notes that the Utilities' ECOSS assigns Account No. 385 costs to all customers within S.C. 2 and 4. Id. at 28, 29.

On these facts, the AG notes, Mr. Glahn explained that "it only makes sense to charge a special 'facilities' charge or 'metering surcharge' to these individual customers. GCI Ex. 6.0 at 5. He further noted that: "It makes no sense for a dry cleaner, a small restaurant, or another small business in S.C. No. 2 to pay for the special, industrial-grade equipment needed for an electric power plant or a similar customer, just because that customer decided to switch from S.C. No. 7 to S.C. No. 2." As an example, Mr. Glahn noted if the electric power plant causing one-third of the account's costs moves back into S.C. No. 7, small business in S.C. No. 2 may be paying for these costs for years "even though the customer causing those costs is not even a member of the class and may be paying for the same costs again in its new rates." Id. at 6.

The AG notes Peoples Gas to argue that its methodology of assigning Account No. 385 costs results in *de minimis* price changes to S.C. No. 2 customers. PGL-NS Int. Br. at 150. This is not a persuasive argument, the AG contends, given the Utility's admission that: (1) the number of customers who trigger the cost is small; and, (2) the costs can be traced to individual customers. The AG urges that Mr. Glahn's common sense approach to assigning Account No. 385 costs be adopted by the Commission. Such a cost assignment, the AG asserts, would promote the goals of equity and fairness in the allocation of the Utilities' costs.

(4) Peoples Gas' Response

According to Peoples Gas, it is undisputed that: (1) the Utility can track FERC Account No. 385 costs to individual customers; (2) customers that cause Peoples Gas

to incur costs recorded in Account No. 385 may migrate from one rate classification to another; and (3) the number of customers who cause Peoples Gas to incur such charges is small. NS-PGL Ex. RJA-2.0 at 17-18; *see also* Tr. at 324-25 (Amen). Nevertheless, Peoples Gas argues, these facts do not support Mr. Glahn's various proposals.

The AG similarly offers no authority for its position that there is an "overriding preference" for direct assignment of costs. Instead, the AG joins GCI in singling out particular costs and declaring that they should not be allocated to the class simply because they are identifiable to a specific customer. As Mr. Amen testified, there are many costs that could be so identified, and to begin with Account No. 385 costs could open the floodgates for broader direct assignment. PGL-NS Ex. RJA-3.0 at 10. This, Peoples Gas argues, can only lead to fractured and unnecessarily numerous rates and charges for the Utilities. Instead, the Utilities propose that a sound rate structure should include the practical attributes of simplicity, understandability, certainty and feasibility of application. Id. at 10-11.

(5) Commission Analysis and Conclusion.

The issue at hand is whether Account No. 385 costs should be directly assigned, to individual customers for the purpose of determining customer–specific charges, as proposed by GCI but as opposed by Peoples Gas.

We pay special attention here to the respective testimonies of the Utilities witness Amen and the GCI's witness Glahn. On the basis of our review, Mr. Glahn's account and his reasoning are far more persuasive than anything we hear on the Utility's side.

Account No. 385 represents industrial measuring and regulating station equipment expense. Mr. Glahn proposes that Account 385 costs should be directly charged as a facilities charge or metering surcharge to the individual customers generating those costs and for reasons that Peoples Gas can track the costs of Account No. 385 facilities to individual customers; the customers may move from one rate classification to another; and the small number of customers causing the cost justifies a direct charge.

The Commission is far less impressed with the Utility's claim that the overall impact of the issue Mr. Glahn raises is extremely small, i.e., Account No. 385 represents less than 0.04% of Peoples Gas' customer related distribution plant. In our view, there is much more to the situation. Mr. Glahn's proposal rests on questions of fairness and equity with respect to the treatment of customers whose costs can be specifically identified to them. Where, as here, the Commission sees that the Utilities have the capability to identify the specific plant costs of meters, regulators and services with individual customers in all of its service classes, we consider it appropriate to rely on those attributes. To the extent practicable, a sound rate structure should include the practical attributes of simplicity, understandability, certainty and feasibility of application. In the final analysis, the Commission finds GCI witness Glahn's proposal to be consistent with these objectives, fair in implementation, and it is approved.

e) Differentiated Class Rates of Return

(1) North Shore / Peoples Gas

The Utilities assert that they have satisfied the requisite statutory burden with respect to their proposed allocation of the revenue requirement. The Utilities calculated, at present rates, an average return in their respective ECOSS' of 4.88% for Peoples Gas and 7.12% for North Shore. PGL Ex. RJA-1.0, 33; NS Ex. RJA-1.0, 33. The Utilities' witness, Mr. Amen, testified that his ECOSS allocates revenue responsibility at an equalized class rate of return on investment of 8.25% for Peoples Gas, and 8.57% for North Shore, under proposed rates. PGL-NS Ex. RJA-1.0 at 2.

(2) CUB-CITY

City-CUB note that the ECOSS prepared by Utilities witness Amen allocates revenue responsibility at equal class rates of return. NS-PGL Ex. RJA-2.0 at 19. As such, they explain, the ECOSS is premised on the assumption that each customer class contributes the same level of risk to the Utilities' overall risk profile. City-CUB Ex. 2.0 (Public) at 29. According to City-CUB witness Thomas, however, this assumption is unsupported. And, as Mr. Thomas explained, there is ample reason to conclude that the relative risk of serving customers varies by customer class. In particular, he stated that:

> [c]ommercial and residential customers use gas very differently, and their usage is affected by different factors. For example, residential usage tends to vary with weather, while commercial and industrial usage tends to vary with general economic conditions. This means that there are very different risk factors related to the revenue the Utilities receive from each customer class.

City-CUB Ex. 1.0 at 77.

City-CUB maintain that Mr. Amen did not address these considerations, and only rejoined that no evidence has been presented suggesting that adopting risk-adjusted class rates of return is appropriate "for consideration in this instant case." NS-PGL Ex. RJA-2.0 at 19. According to the City-CUB, this assertion reverses the statutory allocation of the burden of proof. They assert that the utilities alone – not Staff or intervenors – bear the burden of proof to establish that their proposals are just and reasonable. 220 ILCS 5/9-201(c). To demonstrate that the Utilities have failed to meet their statutory burden with respect to their proposed allocation of the revenue requirement, City-CUB need not adduce evidence disproving the Utilities' *assumption* that the risk that the Utilities will not recover the costs of service does not vary by customer class. In the view of City-CUB, it is sufficient to point out, as Mr. Thomas did, that "there is "absolutely no evidence" supporting their assumption. City-CUB Ex. 2.0 (Public) at 29.

The City-CUB further claim that the Utilities' apparent reliance on speculation in allocating their revenue requirement makes plain that the Commission should avoid treating the ECOSS as a flawlessly objective basis for apportioning the revenue

requirement among the customer classes. To be clear on this, City-CUB do not advocate that the Commission completely disregard the Utilities' ECOSS. Indeed, their witness Thomas explained that the ECOSS can be a useful starting point – albeit not the conclusive basis – for setting just and reasonable rates and charges. City-CUB Ex. 1.0 at 78. But to the extent the ECOSS is used for that purpose, City-CUB agree that the Commission should ensure that the study attributes costs to each customer class as accurately as possible. *See* Id.

(3) North Shore / Peoples Gas Response

The Utilities point out that City-CUB witness Thomas was the only witness to interpret their ECOSS methodology as assuming that each customer class contributes in precisely the same way to the Utilities' required rate of return. In addition, they note, Mr. Thomas to suggest that residential customers' gas usage is affected by the weather, while commercial customers' usage is affected by economic conditions, such that each customer class must provide a different level of risk to the overall cash flow risk of the Utilities and that each should pay rates which are established under separate rate of return assumptions. The Utilities note, however, that Mr. Thomas made no effort to support his observation with an analysis of these purported different risks. Indeed, he admitted that he was not even proposing any specific adjustments, but merely making an observation to cast doubt on Mr. Amen's ECOSS results. CUB-City Ex. 1.0 at 77.

City-CUB maintain that the Utilities failed to carry their burden of proof on this issue, but the Utilities assert that their burden centers around whether they have properly identified the cost responsibility of the customer classes on an equal footing at the system average or "equalized" rates of return, which provides the correct starting point for determining an appropriate level of class revenue responsibility. The Utilities submit that they have done just that.

(4) Commission Analysis and Conclusion

The Commission is unpersuaded with the analysis and arguments of City-CUB and Mr. Thomas. There is no support for the position and City-CUB misapprehend the burden of proof in this instance. The Commission finds that, absent some demonstrated causal link between a utility's customer class composition and its capital costs, the concept of relative customer class risk is inapplicable as a basis for setting customer class target rates of return within the framework of a cost of service study such as the ECOSS submitted by the Utilities in this proceeding. Therefore, the Commission accepts and approves the Utilities' rate of return proposals as fair and reasonable.

IX. RATE DESIGN

A. Overview

(This account, provided by the Utilities outlines the scope of this Part of the Order).

The Utilities have not filed a rate case since 1995, and the current tariff book was created that year. The tariff books that the Utilities submitted in these proceedings, they point out, are completely new and have been submitted as IL.C.C No. 28 and IL.C.C

No. 17 for Peoples Gas and North Gas, respectively. PGL Ex. VG-1.1 and NS Ex. VG-1.1.

In designing rates, the Utilities maintain that they have sought to accomplish six major objectives. These are to: (1) better align costs and revenue recovery; (2) provide more equity between and within rate classes; (3) maintain rate design continuity; (4) reflect gradualism; (5) retain customers on the Utilities' systems; and, (6) consolidate certain transportation riders while providing new service options for transportation customers. PGL Ex. VG-1.0 REV at 4; NS Ex. VG-1.0 2REV at 4.

The Utilities explain that they have presented analyses that reflect their revenues under present and proposed rates with Rider UBA. *See* PGL Ex. VG-1.1; NS Ex. VG-1.2. These exhibits also reflect the proposed transportation diversity factors of .87 and .75 for transportation customers of Peoples Gas and North Shore, respectively. *See*, PGL Ex. VG-1.0 REV at 5; NS Ex. VG-1.0 2REV at 5; and PGL Ex. VG-1.2, 1; NS Ex. VG-1.2, 1. The Utilities have submitted additional exhibits which show rate and revenue impacts with Rider UBA expenses recovered through base rates, rather than through a rider mechanism. *See* PGL Ex. VG-1.0 REV at 5; NS Ex. VG-1.0 3REV at 5; and PGL Ex. VG-1.2, page 2 and NS Ex. VG-2.1, page 2. Rider UBA places recovery of the gas cost portion of uncollectible expense in a rider rather than base rates. If the Commission does not approve this proposal, the Companies' base rates must include the full uncollectible expense. Accordingly, the Companies' rate and revenue data reflect the preferred rate design, which includes Rider UBA as well as rate and revenue data with uncollectible expense in base rates without Rider UBA.

The Utilities explain that they have utilized Mr. Amen's ECOSS as the basis for the determination of the revenue requirement and resulting proposed rates in this proceeding, including the analyses without Rider UBA. They used the ECOSS to move rates toward cost-based rates and to better align charges with like costs. The ECOSS was also used as the basis for bifurcating Service Classification No. 1 into two new service classifications: S.C. No. 1N, Small Residential Non-Heating Service, and S.C. No. 1H, Small Residential Heating Service. PGL Ex. VG-1.0 REV at 6; NS Ex. VG-1.0 3REV at 6. Utilizing the ECOSS results which determine the cost of service for each service classification, North Shore proposes to continue to set all its service classifications at cost. Peoples Gas proposes to set all service classifications, except S.C. Nos. 1N, 1H, and 2, at cost. The remaining revenue requirement for S.C. Nos. 1N, 1H and 2, is allocated utilizing the equal percentage of embedded cost ("EPEC") methodology (discussed in more fully in section B(1) of this Section IX).

Almost all of the Utilities' costs, about 95% for Peoples Gas and about 98% for North Shore are fixed, i.e., they do not vary with throughput, and the Utilities have traditionally recovered a greater portion of their costs through non-fixed volumetric charges. The Utilities' last rate case filed about 12 years ago reflected costs that were 98% and 97% fixed for Peoples Gas and North Shore, respectively. Less than 30% of fixed costs were recovered through fixed charges. *See*, Dockets Nos. 95-0031 and 95-0032. This mismatch of fixed costs and non-fixed charges practically assures that the Utilities will either over or under-earn their Commission approved revenue requirement and that customers will either over or under pay their share of such costs. To partially

remedy this, the Utilities are proposing to recover more fixed costs through fixed charges. PGL Ex. VG-1.0 REV at 8-9; NS Ex. VG-1.0 3REV at 6-7.

Generally the Utilities have proposed to increase customer charges in an effort to recover more fixed costs in the fixed charge. The relative increase in customer charges proposed by the Utilities is consistent with a growing trend whereby public utility commissions have approved greater fixed cost recovery in fixed charges. This trend has resulted in the approval of rate models where all fixed cost are recovered through a fixed charge, such as the Straight Fixed Variable "SFV" rate design or customers paying a largely flat charge for utility delivery service, with little or no volumetric charge. *See* Re Atlanta Gas Light Company*,* 2001 WL 1776861 (Ga. P.S.C., Sep 18, 2001) (Docket. No. 8516-U). Greater fixed cost recovery through customer charges stabilizes the non-gas cost delivery charge portion of customers' bills and stabilizes the variability in earnings related to variations in customer consumption caused by weather and other conditions outside the Utilities' control. While the Utilities maintain that an SFV rate design would be the optimal one, PGL Ex. VG-1.0 REV at 17; NS Ex. VG-1.0 3REV at 14, they are proposing only to recover a greater portion of fixed cost through increased customer charges.

The particulars of the rates and rate design proposals of the Utilities and other parties are discussed below.

Generally, as to Peoples Gas, the Company has proposed ten major changes to its base rates and other charges. These are the following.

1. S.C. No. 1, Small Residential Service, will be bifurcated into two service classifications: S.C. No. 1N, Small Residential Non-Heating Service, and S.C. No. 1H, Small Residential Heating Service.

2. The monthly customer charge for S.C. No. 1N customers will be increased. The distribution charge, which is a two-block rate structure under current S.C. No. 1, will become a flat charge.

3. The monthly customer charge for S.C. No. 1H customers will be increased. The distribution charge will reflect a decrease in the end block with a greater percentage of costs being allocated to the front block of the current two-block rate structure.

4. The monthly customer charges for each Meter Class under S.C. No. 2, General Service, will be increased. The distribution charge will reflect an increase in the front and middle blocks and a decrease in the end block of the three-block rate structure.

5. S.C. No. 3, Large Volume Service, and S.C. No. 4, Large Volume Demand Service, will be combined under S.C. No. 4. S.C. No. 3 will be eliminated. The monthly customer charge and demand charge will be decreased. The distribution charge and standby service charge will be increased. This service classification is set at cost.

6. The monthly customer charge and distribution charge for S.C. No. 6, Standby Service, will be increased. The demand charge will be decreased and

will reflect a single demand charge rather than the separate demand charges for heating and non-heating customers under current rates. This service classification is set at cost.

7. The customer charge and distribution charge for S.C. No. 8, Compressed Natural Gas, will be increased. This service classification is set at cost.

8. Service reconnection charges and service activation charges will be restructured to reflect a base charge and charges for additional appliances.

9. The Charge for Dishonored Checks and/or Incomplete Electronic Withdrawal will be increased to better reflect prevailing rates for such checks and transactions and to discourage customers from making such deficient payments to the Company.

10. The Company is proposing a new charge for a Second Pulse Data Capability to accommodate customers' requests for this service.

See PGL Ex. VG-1.0 REV at 9-10.

Generally, as to North Shore, the Company has proposed nine major changes to its base rates and other charges. These are the following.

1. S.C. No. 1, Small Residential Service, will be bifurcated into two service classifications: S.C. No. 1N, Small Residential Non-Heating Service, and S.C. No. 1H, Small Residential Heating Service.

2. The monthly customer charge for S.C. No. 1N customers will be increased. The distribution charge, which is a two-block rate structure under current S.C. No. 1, will become a flat charge. This service classification is set at cost.

3. The monthly customer charge for S.C. No. 1H customers will be increased. The distribution charge will reflect a decrease in the end block with a greater percentage of costs being allocated to the front block of the current two-block rate structure. This service classification is set at cost.

4. The monthly customer charges for each Meter Class under S.C. No. 2, General Service, will be increased. The distribution charge will reflect an increase in the front and a decrease in the middle and end blocks of the three-block rate structure. This service classification is set at cost.

5. The monthly customer charge, distribution charge, demand charge and standby service charge for S.C. No. 3, Large Volume Service will be decreased. The increased. The demand blocks for this service classification will be changed from 5,000 therms and over 5,000 therms to 10,000 therms and over 10,000 therms. This service classification is set at cost.

6. The monthly customer charge and distribution charge for S.C. No. 5, Standby Service, will be increased. The demand charge will be decreased. This service classification is set at cost.

7. Service reconnection charges and service activation charges will be restructured to reflect a base charge and charges for additional appliances.

8. The Charge for Dishonored Checks and/or Incomplete Electronic Withdrawal will be increased to better reflect prevailing rates for such checks and transactions and to discourage customers from making such deficient payments to the Company.

9. The Company is proposing a new charge for a Second Pulse Data Capability to accommodate customers' requests for this service.

See Ex. VG-1.0 REV at 7-9.

The Utilities indicate that only certain of these proposals are contested. Here, the Commission begins to consider and discuss the entirety of the proposals.

B. General Rate Design

1. Allocation of Rate Increase

a) The Utilities

North Shore proposes to continue to set all its service classifications at cost. Peoples Gas proposes to set S.C. Nos. 4, 6 and 8 at cost and to allocate the remaining revenue requirement among S.C. Nos. 1N, 1H and 2 utilizing the equal percentage of embedded cost (EPEC) method. The EPEC method allocates the remaining revenue requirement in proportion to the embedded costs of service for these three service classifications and the resulting amounts are added to the revenue generated under currently applicable rates for the particular service classification to arrive at the revenue to be provided under proposed rates. PGL Ex. VG-1.0 REV at 6; NS Ex. VG-1.0 3REV at 6.

According to the Utilities, the EPEC method provides a gradual movement toward full cost recovery for the small residential customer service classifications. It also provides a gradual movement toward equalizing rates of return for these service classifications. PGL Ex. VG-1.0 REV at 7. It would appear that all parties support the notion that, ideally, all service classifications should support their full cost of service.

Indeed, the Utilities assert, all service classifications should support their full cost of service. For various historical and policy reasons, however, the rates of Peoples Gas' small residential service classification have been set below costs. In order to avoid the rate spikes that would attend moving residential service classifications to costs, Peoples Gas contends that it has applied a policy of gradualism in the movement toward full cost and the Commission has heretofore endorsed this gradualism in its approval of the EPEC method. *See* Peoples Gas Light and Coke Co., Docket Nos. 91-0586 and 95-0032.

While no party appears to quarrel with the notion of gradualism being employed in these proceedings, the Utilities observe that two of the witnesses appear to take issue with the rate increase allocations that result from application of the EPEC mechanism. According to the Utilities, however, no other party has proposed a method that is definable and supportable, like the EPEC methodology, although a third party

offers a vague alternative to Peoples Gas' proposal. If anything, the Utilities argue, the rate increase allocation proposals for Peoples Gas by other parties appear to have been arbitrarily derived and none have been accompanied by analysis which would show the impact of their proposals on customers' bills. In short, only Peoples Gas has provided a reasoned and specific analysis to support its rate increase allocation and only the Companies have shown how their specific rate proposals would affect customers.

b) AG

The AG notes the Utilities to propose using the Equal Percent of Embedded Cost ("EPEC") method of allocating the approved revenue requirements in this case. As such, the Utilities propose to set S.C. Nos. 4 (Large Volume Service), 6 (Standby Service) and 8 (Compressed Natural Gas service) to cost. PGL Ex. VG-1.0 at 6. The remainder of the rate increase, i.e., $72.9 million, is to be allocated among the residential and small business rate classes, S.C. 1 Non-heating, 1 Heating and 2 General Service. PGL Ex. VG-1.3.

The AG observes Utilities' witness Grace to assert that the EPEC method used by the Utilities "moves the small residential service rates closer to cost in a gradual manner." PGL Ex. VG-1.0 at 7. In the AG's view, however, the proposed rate design in this case, which includes a doubling of the customer charge forPeoples Gas's residential customers and an 88 percent increase for North Shore's residential customers, belies this assertion. In addition, the AG sees no real explanation to be given for combining the Rate 2 class (which serves commercial and some industrial customers).

According to the AG, Mr. Glahn identified several problems with the Utilities' application of the EPEC methodology. He observed that instead of equalizing rates across all service classifications, the Utilities chose to equalize rates across arbitrary subgroups, and in doing so, they propose disparate increases among various customer classes that do not meet sound rate design criteria. GCI Ex. 1.0 at 12. Mr. Glahn also observed that the proposed allocated revenue increase raises the cost recovery percentage of most classes, however, the business classifications "are not treated remotely the same", and this violates the principle of horizontal equity, i.e. that equals be treated equally. Id. He notes that S.C. 2 gets an increase of almost 22 percent, but S.C. 3 gets an increase of only 14 percent and S.C. 4 receives an increase of less than one-tenth that size at 2.12 percent. Id. at 12,13. As shown in VG-1.3, page 2, the AG notes, S.C. 4 would continue to pay less than its assumed cost of service, while S.C.2 would go from slightly below cost to more than 21 percent above cost. Id.

Moreover, the AG points out that, despite being grouped with S.C.6 and 8, S.C. 7 is allocated none of the increase because, according to Ms. Grace, the revenues from S.C.7 are based on negotiated, contract rates. Id. at 13, citing PGL Ex. VG-1.0 at 8. The AG argues that Mr. Glahn was correct to note that regardless of how prices are determined for members of S.C. 7, there is a cost to serve these customers in that these customers use the same system facilities and services as all of the other S.C. customers. GCI Ex. 6.0 at 8. As such, the AG asserts, some of the increases in costs that the Company alleges have occurred should be imputed to S.C. 7 customers. And,

whether the Utilities elect to recover these additional costs from S.C.7 customers is up to them. Id. at 9.

Instead of the Utilities' arbitrary groupings, the AG maintains that the Commission should adopt Mr. Glahn's modified version of the utilities' methodology that is more akin to an equal percentage of revenue increase, as detailed in GCI Ex. WLG-3.1, Schedule 2. The AG explains that Mr. Glahn's methodology would be applied across all service classifications, without regard to the PGL-NS sub-groupings. GCI Ex. 3.0 at 14. In order to achieve more fairness and equity across the rate classes, Mr. Glahn set S.C. Nos. 6 and 8 at their assumed cost of service, as the Utilities did. But, he recommends imputing an increase of 26.6 percent (the average system increase) to S.C.7, to reflect the increase in the cost to serve these customers. Id.

To achieve horizontal equity, the AG observes that Mr. Glahn assigned the three business rate classes, Nos. 2, 3 and 4, the same percentage increase of 21 percent, which is far less than the average 26.6 percent increase for all rate classes. Id. He noted that having all three receive the same percentage increase in revenues preserves the horizontal equity of these groups, but in setting their increases at less than the Utilities' average moves two of these classes toward their cost of service. Id. Mr. Glahn noted that this approach still leaves S.C. 2 paying 121 percent of assumed costs, while having S.C.3 pay only 107 percent and S.C.4 pay 116 percent. Id. As Mr. Glahn explained, this result appears much more equitable than having the business customers in S.C.2 paying 121 percent of cost, while business customers in S.C.4 paying only 98 percent. Id.

For the two S.C.1 designations, the AG notes, Mr. Glahn recommended that non-heating customers allocated the same dollar amount as allocated by Utilities' witness Grace in her Exhibit VG-1.2, page 2, with the remaining increase going to heating customers. Id. He testified that this allocation improves horizontal equity by moving the two subgroups closer together. Id. at 14-15.

The AG observes Utilities' witness Grace to have stated that Rate 4 customers must "be set at cost." PGL-NS Ex. VG-2.0 at 16. Mr. Glahn noted, however, that the testimony of Mr. Amen indicated that S.C. 2 includes "many relatively large customers", including one large industrial customer that was formerly a member of S.C.7 (Contract Rates for Bypass Service). GCI Ex. 6.0 at 9. So, Mr. Glahn observed that S.C.2 includes at least one large customer that has an "economically feasible and practical" ability to bypass the system. Id. Yet, Mr. Glahn pointed out, Peoples Gas sees fit to impose upon that customer and others in S.C.2 rates equal to 124 percent of their cost of service. Id.

The AG maintains that Mr. Glahn's proposed revenue increase allocation for these classes is less arbitrary than what the Company proposes, comports with principles of fairness and equity, and should be adopted.

c) City-CUB

City-CUB observe that Peoples Gas' various rate classes, other than S.C. 2, are not currently at their respective cost of service levels, as the Utilities would propose. GCI Ex. 3.0 REV. at 11. To move the utility's classes closer to cost of service, they note

that the Utilities propose moving Peoples Gas S.C. Nos. 4, 6 and 8 to cost, and then apportioning the remaining portion of the proposed revenue requirement – $72.9 million, for Peoples Gas – among S.C. Nos. 1N, 1H and 2 using the EPEC method. The EPEC method, they explain, allocates the increase portion of the proposed revenue requirement based on the class's proportion of embedded costs to total embedded costs. PGL Ex. VG-1.0 REV. at 6. And, the City-CUB note Peoples Gas to assert that this approach "provides a gradual movement" toward equal class rates of return. Id. at 7. Although City-CUB agree that gradualism and equity are laudable goals, they maintain that the utility's proposed allocation of the Peoples Gas rate increase nonetheless should be adjusted as recommended by Mr. Glahn to more equitably apportion the increase.

According to City-CUB, the Utilities' allocation proposal violates the principle of horizontal equity, i.e., that equals should be treated equally, by treating Peoples Gas' business classifications differently. They observe that the proposed allocation results in an increase of almost 22 percent in rates for its S.C. No. 2 customers, but only a 14 percent increase for S.C. 3 customers, and just a 2.12 percent increase for S.C. 4 customers. GCI Ex. 3.0 REV. at 12-13. As Mr. Glahn explained, this inequitable allocation is the result of the Companies' arbitrary grouping of the service classifications: with S.C. 1 and 2 in the first group; S.C. 3 and 4 in the second; and S.C. 6, 7 and 8 in the third. Id. at 13.

City-CUB observe that Ms. Grace discussed the reasons for using the EPEC method to allocate the rate increase among the "small residential" classes – S.C. 1N and 1H – and for proposing to consolidate S.C. Nos. 3 and 4. *See* PGL Ex. VG-1.0 REV. at 7-8. As to the EPEC method, she maintained the Companies used it to move "S.C. Nos. 1N and 1H toward their respective revenue requirements on a gradual basis." Id. at 7. According to City-CUB, this testimony fails to explain why Peoples Gas has grouped S.C. 2 (the general service class) with S.C. 1N and 1H (both small residential classes) in allocating the utility's proposed rate increase. Similarly, City-Cub observe, her stating that S.C. 3 and 4 should be combined because the difference in average load factors between the two classes has "significantly narrowed" does not explain why these two business classes were not grouped with S.C. 2 in apportioning the rate increase. Id. at 24.

City-CUB observe that Ms. Grace's discussion of the differences in the average annual loads and rate structures of S.C. 2 and S.C. 4 does not explain why S.C. 2 was grouped with small residential customers rather than with S.C. 3 and 4. *See* NS-PGL Ex. VG-3.0 at 6-7. Also missing, in their view, is any comparison of the respective differences in average annual loads and rate structures between S.C. 2 and S.C. 4 on the one hand, and between S.C. 2 and S.C. 1N and 1H on the other. According to City-CUB, the Utilities have not shown that S.C. No. 2 is more similar in terms of annual load to S.C. Nos. 1N and 1H than to the combined S.C. No. 4, and therefore should be grouped with S.C. 1 rather than S.C. 4. Indeed, they note Ms. Grace to concede that there are "some large volume load customers" in S.C. 2, id. at 6, including the electric power plant identified by Mr. Amen. Id. at 6-7; NS-PGL Ex. RJA-2.0 at 17.

Another flaw that City-CUB perceives in the Utility's proposed allocation of the rate increase is that, while it is grouped with S.C. 6 and 8, S.C. 7 is not allocated any of the increase. Peoples Gas asserts this omission is appropriate because "the revenues from customers served under this service classification are based on a negotiated [contract] rate rather than the cost of service analysis filed in this case." PGL Ex. VG-1.0 3REV. at 8. Mr. Glahn, however, testified that "[r]egardless of how prices are determined for members of Service Classification No. 7, there is a cost to serve these customers." GCI Ex. 3.0 REV. at 13.

City-CUB observed Ms. Grace to have countered that: (a) the contracts for customers served under S.C. 7 are limited to five-year terms, and have been renegotiated "based on the proper cost considerations," and cannot be modified to include a portion of the proposed rate increase; (b) Mr. Glahn did not explain how Peoples Gas would recoup revenue from contracts that are not renewed because of actual bypass; and, (c) revenues arising from S.C. No. 7 "contribute to recovery of Peoples Gas' fixed costs and mitigate any increase on Peoples Gas' system customers." NS-PGL Ex. VG-2.0 at 17. In the City-CUB's view, these responses do not rebut, or even address, Mr. Glahn's fundamental argument that S.C. No. 7 customers use the same system facilities and services as customers in other service classifications, and the cost of building, operating and maintaining those facilities and services has risen since the Companies' last rate case. *See* GCI Ex. 6.0 REV. at 8-9. They maintain that Ms. Grace's vague reference to purportedly "proper cost considerations" and the claim that S.C. 7 customers contribute to recovery of distribution costs should not distract the Commission from observing that Peoples Gas allocated none of its proposed rate increase to S.C. 7.

As to the mechanics of recovering a portion of the rate increase from S.C. No. 7, City-CUB note that the Utilities have not stated whether their contracts with S.C. 7 customers include a provision for incorporating supervening changes in the Companies' rates approved by the Commission – and if not, why this is so. To the extent the Utilities did not include such a provision in the contracts, City-CUB believe that omission should not serve as a basis for shifting S.C. 7 cost increases to other customer classes through the allocation process. In any event, they argue, whether and how Peoples Gas chooses to recover those additional costs from S.C. No. 7 customers is up to the utility. Id. at 9.

City-CUB point out that by taking well established equity principles into account, Mr. Glahn proposed an alternative allocation of the revenue increase, more akin to an "equal percentage of revenue increase." GCI Ex. 3.0 REV. at 14. In particular, he set S.C. 6 and 8 at their assumed cost of service, as Peoples Gas did, but imputed the average system increase (26.6 percent) to S.C. 7, to reflect the increase in the cost of serving customers in that class. Like Peoples Gas's proposed allocation to S.C. 1N and 1H, Mr. Glahn's alternative allocation would, in the interest of gradualism and equity, move these residential classes closer to, but not entirely to, their cost of service levels. To better serve horizontal equity, however, Mr. Glahn allocated the same 21% increase to S.C. 2, 3 and 4, moving S.C. 2 to 121 percent of cost and S.C. 3 and 4 to 107 percent and 116 percent above cost, respectively.

This, the City-CUB argue, is a more equitable allocation for the business classes than having S.C. 2 at 121 percent of cost, while having the combined S.C. 3 and 4 class at cost, as Peoples Gas proposes. Id. at 14-15. Moreover, they consider Ms. Grace's claim, that it is important to set S.C. 4 at cost because customers in that class may be able to bypass Peoples Gas's system (NS-PGL Ex. VG-6.0 REV. at 16), to not undermine the basis for Mr. Glahn's proposal to move S.C. 4 above cost, given that both his proposed allocation, and that of Peoples Gas, would move S.C. 2 considerably above cost. According to City-CUB, to increase S.C. 2 rates above cost while setting combined S.C. 4 rates at cost (simply for the reason that S.C. 2 customers do not have the same ability to physically bypass Peoples Gas' system) is patently unfair.

In City-CUB's view, Peoples Gas' allocation of its proposed rate increase violates the principle of horizontal equity by treating business customers in S.C. 2 and combined S.C. 4 differently. In addition, the utility has improperly failed to allocate to S.C. 7 any of the increase in the cost to serve that class. Mr. Glahn's alternative allocation more equitably apportions the rate increase among Peoples Gas S.C. 2 and combined S.C. 4 and properly imputes a portion of the proposed rate increase to S.C. 7. Accordingly, the Commission should reject Peoples Gas's proposed rate increase allocation and instead adopt Mr. Glahn's alternative allocation.

It is unclear to City-CUB why, in apportioning its proposed rate increase, Peoples Gas grouped S.C. 2, the general service class, with S.C. 1N and 1H, both small residential classes, rather than with S.C. 3 and 4. Although to justify this grouping, Ms. Grace pointed to differences in average annual loads and rate structures of S.C. 2 and 4 (*see* NS-PGL Ex. VG-3.0 at 6-7), City-CUB claim that she did not compare the respective differences between S.C. 2 and S.C. 4 on the one hand, and between S.C. 2 and S.C. 1N and 1H on the other. As such, City-CUB argue, the Utilities have not shown that S.C. No. 2 is more similar in terms of annual load to S.C. Nos. 1N and 1H than to the combined S.C. No. 4. therefore should be grouped with S.C. 1 rather than S.C. 4.

City-CUB contend that the Companies ignore Mr. Glahn's specific alternative allocation of the revenue increase, which is more akin to an "equal percentage of revenue increase." GCI Ex. 3.0 REV. at 14. In particular, Mr. Glahn set S.C. 6 and 8 at their assumed cost of service, as Peoples Gas did, but imputed the average system increase (26.6 %) to S.C. 7, to reflect the increase in the cost of serving customers in that class. To better serve horizontal equity, Mr. Glahn allocated the same 21% increase to S.C. 2, 3 and 4, moving S.C. 2 to 121 percent of cost and S.C. 3 and 4 to 107 percent and 116 percent above cost, respectively. According to City-CUB, this is a more equitable allocation for the business classes than having S.C. 2 at 121 percent of cost, while having the combined S.C. 3 and 4 classes at cost, as Peoples Gas proposes. Id. at 14-15. Nor should the Commission be distracted by the Companies' sweeping misstatement that other parties' alternatives to Peoples Gas's proposed alternatives to the utility's rate increase allocation were "arbitrarily derived." PGL-NS Init. Br. at 159.

According to City-CUB, Peoples Gas's allocation of its proposed rate increase violates the principle of horizontal equity by treating business customers in S.C. 2 and

combined S.C. 4 differently. In addition, the utility has improperly failed to allocate to S.C. 7 any of the increase in the cost to serve that class. GCI's alternative allocation, which more equitably apportions the rate increase among Peoples Gas S.C. 2 and combined S.C. 4, also imputes a portion of the proposed rate increase to S.C. 7. Accordingly, the Commission should reject Peoples Gas's proposed allocation of its rate increase and instead adopt GCI's alternative allocation.

d) Utilities Response

The Utilities observe that no party appears to quarrel with the notion of gradualism being employed in these proceedings. They note, however, that two of the witnesses appear to take issue with the rate increase allocations that result from application of the EPEC mechanism. Nevertheless, the Utilities point out, no party has proposed a method that is definable, supportable, and reasonable like the EPEC methodology (although one party does set out a vague, but interesting alternative to Peoples Gas' proposal).

The Utilities observe Staff witness Luth to take issue with certain aspects of the Peoples Gas allocation of the proposed rate increase to customer classes. Mr. Luth proposes specific rates for S.C. Nos. 1N and 1H as well as a specific amount of the remainder of the S.C. Nos. 1N and 1H increase that would be allocated to S.C. No. 2 based on the revenue requirement that he determined. According to the Utilities, however, Mr. Luth's methodology for this allocation is flawed. His proposal is driven by specific charges for S.C. Nos. 1N and 1H, and a specific amount for the increase that would be allocated to S.C. No. 2, rather than an overarching method that could be readily and objectively applied to a revenue requirement that would differ from his own. While Mr. Luth achieves rate outcomes that may not be unreasonable, the Utilities observe that his methodology is not capable of being applied predictably and readily to the revenue requirement that will ultimately be determined in this Order.

For his part, the Utilities observe that Mr. Glahn's sole basis for criticizing the EPEC method is his belief that it applies arbitrary customer class groupings. The Utilities note, however, that Mr. Glahn never explains why he believes these customer class groupings under the EPEC are arbitrary. Instead, he simply recites the revenue cost ratio effect of the EPEC method and proceeds to inappropriately allocate additional costs to one service classification (S.C. No. 4), which is set at cost, and to another service classification, (S.C. No.7), where contractually set rates already reflect the appropriate cost considerations. The Utilities maintain that Mr. Glahn ignores the purpose of the groupings, which is simply to employ the EPEC methodology, and to set S.C. No. 4 (which combines two similar service classifications) at cost. The Utilities point out that Ms. Grace explains in detail, and on record, why S.C. No. 4 should be set at cost and why Mr. Glahn's proposal for S.C. No. 7 is not appropriate.

Finally, the Utility points out, Mr. Glahn's methodology is mathematically incorrect and results in an increase which is $533,971.00 higher than what has been proposed by Peoples Gas. *See* NS-PGL Ex. VG-2.2, pg. 1, columns A and D and GCI Ex. 3.0, Ex. WLG-D, Schedule 2, column (4). And, where both Peoples Gas and Staff support setting S.C. No. 4 at cost, Mr. Glahn alone supports setting S.C. No. 4 over cost or allocating costs to S.C. No. 7. In the Utility's view, Mr. Glahn's S.C. Nos. 4 and 7

proposals are even more problematic because he inappropriately allocates additional costs to these service classifications, and offers no specific rate design proposals for either one.

The Utility observes that Neil Anderson, on behalf of Vanguard, proposes to phase in increases for rate classifications to reach cost over a five (5) year period. His proposal, however, is devoid of details. While Mr. Anderson characterizes his proposal as a rate design proposal, he does not offer any rates or meaningful rate design proposal for any service classification. His exhibit (VES Ex. 3), which supports his "rate design proposal", reflects revenue allocations for years 1 through 4 that are consistent with Peoples Gas' EPEC revenue allocation. It is unclear to the Utility as to how the revenue allocation in year 5 (VES Ex. 3, line 9) was derived. And, it should be noted that the service class revenues in year 5 (id.) do not sum to the total company revenues and the total revenue amount is not consistent with any revenue amount proposed by any party in this proceeding. Peoples Gas agrees that it is appropriate to move all service classifications to cost, and it is taking significant steps in this case, including bifurcating S.C. No. 1 into heating and non-heating rates, to move S.C. No. 1 to cost. *See*, NS-PGL Ex. VG-2.0 at 17-18. In the end, however, Mr. Anderson's proposal lacks sufficient detail for the Commission to evaluate and should be rejected.

Indeed, the Utility argues, the rate increase allocation proposals for Peoples Gas by other parties appear to have been arbitrarily derived or are improper and none have been accompanied by analysis which would show the impact of their proposals on customers' bills. As such, only Peoples Gas has provided a reasoned and specific analysis to support its rate increase allocation and only the Companies have shown how their specific rate proposals would affect customers.

e) Commission Analysis and Conclusion

At this juncture, Peoples Gas has proposed to allocate a portion of the S.C. No. 1N and 1H rate increases to S.C. No. 2 by utilizing the EPEC method. We understand that this methodology, mechanical and objective, is not based upon any specific rates or rate design proposals. Instead, it is based upon a defined formula approved in Peoples Gas' two prior rate cases which determines the amount of the small residential service classification rate increase that will be allocated to the S.C. No. 2 revenue requirement. In addition to being precedential, the utilities most definitively explain, there are sound reasons for Peoples Gas to use the EPEC method. NS-PGL RBOE at 36. First, they note Peoples Gas witness Grace explained that the EPEC was applied to S.C. Nos. 1N, 1H and 2 in order to move the two small residential service classifications gradually to cost. PGL Ex. VG 1.0 2REV at 11. Second, S.C. Nos. 3 and 4 were grouped, and proposed to be consolidated, because these two service classifications serve large volume customers with increasingly similar load factors. Id. at 24. Thus, unlike S.C. No. 2, S.C. Nos. 3 and 4 were, and S.C. No. 4 would continue to be, fully unbundled. NS-PGL Ex. VG-2.0 at 16. This distinction highlights the flaw in the GCI's proposed grouping of S.C. Nos. 2 and 4 on the grounds of "horizontal equity." The principle of horizontal equity is to treat equals as equals but, Peoples Gas asserts, S.C. No. 2 is unlike S.C. No. 4 and should not be treated the same. Id. at 11-12. Third, Peoples Gas points out GCI incorrectly state that S.C. Nos. 6, 7 and 8 were grouped. AG BOE at 48;

City-CUB BOE at 55. The Utilities maintain that they presented each of these service classifications separately in both testimony and exhibits. NS-PGL Ex. VG-2.0 at 11. Considering all the matters of record, the Commission finds that the method employed by Peoples Gas assures that the revenue requirement set forth in this Order will be readily and objectively allocated.

At the same time, the Commission is unable to ascertain if Mr. Luth's methodology would readily adapt to a revenue requirement that differs from his own. Similarly, we view Mr. Glahn's proposals for allocating the rate increase for Peoples Gas as too limited in scope and not based on a broadly applicable methodology. It appears that Mr. Glahn would arbitrarily assign an amount of the increase to S.C. Nos. 4 and 7 and without sufficient reasoning to support the assignment. In the case of S.C. No. 7, we specifically note, customers receive service under binding negotiated contracts, and it is not clearly established how such costs could be factored into these contracts. Moreover, Peoples Gas indicates that such contracts reflect the proper cost considerations and while Mr. Glahn raises the issue, he has not shown otherwise. We are further unpersuaded by Mr. Glahn in that he offers no reason why S.C. No. 4 should be set above cost, where the record demonstrates that these customers have some ability to bypass Peoples Gas' system.

In their exceptions, the GCI continued to criticize setting S.C. No. 4 at cost and allocating no cost to S.C. No. 7. Peoples Gas responds and further explains why it is important and beneficial to all customers to set S.C. No. 4 at cost. These are large volume customers, Peoples Gas says, and the service classification is only available to customers with average monthly usage of at least 41,000 therms. PGL Ex. VG-1.1 at 9. Setting this rate over cost could induce these customers to physically or economically bypass Peoples Gas' system. Since its last rate case, Peoples Gas states that the number of such large volume customers has declined significantly and additional losses of such customers would reduce fixed cost recovery. Given that Peoples Gas' costs are overwhelmingly fixed, this would result in higher rates for the remaining customers. NS-PGL Ex. VG-2.0 at 16, 24.

We see no merit to the AG's exceptions claim that S.C. No. 4 rates would be less than its allocated cost. AG BOE at 47. Peoples Gas clarifies that it proposes to combine current S.C. Nos. 3 and 4 into a single service classification to be called S.C. No. 4 and to set S.C. No. 4 at cost. Exhibits that show current S.C. No. 3 at 100.9% of cost and current S.C. No. 4 at 98% of cost combine to show the proposed S.C. No. 4 is at cost. NS-PGL Ex. VG-2.0 at 15-16.

The Commission also finds it reasonable to allocate a portion of the rate increase for S.C. No. 1 to S.C. No. 2 using the EPEC method proposed by Peoples Gas. While Mr. Anderson's proposal raises some interesting ideas in this area, at bottom, the Commission is unable to analyze his concepts for lack of sufficient detail.

2. Gas Cost Related Uncollectible Expense

a) Utilities

According to the Utilities, the only contested issue that concerns Gas Cost Related Uncollectible Expense arises from a rate design perspective centered around

how the gas cost related uncollectible expense would be recovered in base rates when Rider UBA is not approved.

They note that Staff witness Luth is the only party who has taken issue on the record with the Utilities' proposals for the treatment of uncollectible expense if Rider UBA is not adopted. At one point, Mr. Luth had urged that uncollectible expense should be allocated to S.C. Nos. 3 and 4 and Peoples Gas performed an analysis that indicated a portion of bad debt was attributable to S.C. No. 3 and modified the proposals to allocate an appropriate amount to S.C. No. 4. *See* NS-PGL RJA-2.0 at 14.

Ms. Grace and Mr. Luth agree in principle that if Rider UBA is not approved, separate base rates will need to be established for sales and transportation customers. For her part, Ms. Grace has proposed an approach whereby the Utilities' ECOSS, which already reflects the removal of gas cost related bad debt expense, would establish the base rates for all customers, including transportation customers. The Gas Cost Related Uncollectible Expense would then be added to sales customer's base rates, thereby establishing separate rates in a straightforward and simply manner. According to the Utilities, Exhibits VG-2.3-PGL and VG-2.3-NSG illustrate this simple methodology which determines how the Utilities' distribution base rates would be affected. Ms. Grace's approach also allocates uncollectible expenses at full costs to each affected service classification. NS-PGL Ex. VG-2.0 at 21. This is an appropriate approach, the Utilities assert, because it mitigates the impact of such costs on Peoples Gas' S.C. No. 2 which has already been allocated a portion of the rate increase for S.C. Nos. 1N and it is based on cost causation. And, any claim of errors with respect to Exhibits VG 2.3-PGL and VG-2.3-NSG, is simply incorrect. The uncollectible expenses reflected in the referenced exhibits are recovered based on rate class specific historical write-offs, consistent with the approach utilized in Mr. Amen's ECOSS and by Mr. Luth to allocate total uncollectible expense in his ECOSS. Tr. at 1460; NS-PGL Cross Ex. 9 (Luth).

Additionally, the Utilities propose that final credits to transportation customers be based on the gas charge revenues and the gas cost related uncollectible expenses for sales customers as approved by the Commission in this proceeding, rather than any credit based on present rate total gas charge revenues which would inappropriately include a credit arising from transportation customers' own gas charge revenues. In the Utilities view, Mr. Luth mischaracterizes the proposal above to support his proposal for Account No. 904 expenses. While Mr. Amen correctly demonstrated that Account No. 904 expenses is a customer related cost, the Utilities explain that they have elected, at this time, to not recover these customer related costs through the customer charge in their gradualism approach of not recovering all customer costs through the customer charge. NS-PGL Ex. VG-3.0 REV at 13. Therefore, they argue, the determination to recover gas cost related bad debt through the distribution charge is warranted and reasonable.

The Utilities contend that they have also established the necessity for a different rate treatment for sales and transportation customers if Rider VBA or Rider WNA is implemented without approval of Rider UBA. They assert that gas cost related uncollectible expense under such circumstances should be made on a per customer, rather than on a per distribution therm basis. NS-PGL Ex. VG-3.0 REV16-17.

Finally, the Utilities maintain that, if Rider UBA is not approved, gas cost related uncollectible expenses should be recovered entirely through the distribution charge, rather than the customer charge and the distribution charge. Although they assert that Mr. Amen correctly demonstrated that Account No. 904 expense is a customer related cost, the Utilities elect not to recover certain costs through the customer charge in their gradualism approach of not recovering all customer costs through the customer charge. NS-PGL Ex. VG-3.0 REV at 13. They contend that this determination to recover gas cost related bad debt through the distribution charge is warranted and reasonable.

In their Brief on Exceptions, the Utilities argued that the AG's first point pertains to the amount of dollars to be allocated and is unrelated to the underlying rate design issue. The AG's second point is a criticism of the proposed bifurcation of S.C. No. 1 into a heating and non-heating service classification and is, likewise, unrelated to the underlying rate design issue. Similarly, the Utilities argued that the AG's fourth point about proper price signals would be more properly addressed in the larger context of the S.C. No. 1 rate design and not in connection with this design question for a specific cost.

The Utilities stated that the AG's third point, addressing the allocation of the uncollectible expense for S.C. No. 1H between the first and second block, ignores the fact that the Utilities' proposal for this item is consistent with its overall proposal for S.C. No. 1H. Specifically, the Utilities proposed that 67% of the expense be allocated to the front block, just as it proposed for the allocation of costs not recovered through the customer charge. PGL Ex. VG-1.0 at 14; NS Ex. VG-1.0 at 12; *also see* NS-PGL Ex. 3.0 REV at 18. There are no alternative formulaic proposals for determining distribution charges once the Commission sets the revenue requirement and the customer charge component of the service classifications. According to the Utilities, only they proposed specific methods for easily and objectively determining distribution charges, whatever revenue requirement is approved. *See, e.g.*, NS-PGL Ex. VG-3.0 REV at 5, 18, 19, 22.

b) Staff

According to Staff, part of the problem with both Rider UBA and the Utilities' alternative base rate proposal, is the application of a uniform rate to determine the recovery of uncollectible gas costs from customer service classifications subject to Rider UBA, regardless of how each customer class adds to uncollectible gas costs. Staff Ex. 19.0 at 16-17. In Staff's view, the result would be that some customer service classifications would pay more than the amount of uncollectible gas costs those customers add to uncollectible gas costs under Rider UBA or the Companies' proposed alternative recovery of uncollectible gas costs through base rates, while other customer classes would pay less than the amount that those customer classes add to uncollectible gas costs. Since the gas costs and the uncollectible rate among SC 2 customers are different from gas costs and uncollectible rate among SC 1N and SC 1H customers, Staff contends that SC 2 sales customers should pay a different amount per therm for uncollectible gas costs than SC 1N and SC 1H customers. Id. Sched. 19.3-NS and 19.3-PG, lines 5, 10, and 14.

Staff observes that sales customers in each customer service classification are supplied natural gas by North Shore or Peoples Gas, depending upon which company provides gas delivery service to the customer. Staff notes that transportation customers obtain their own supplies of gas which are then delivered by either North Shore or Peoples Gas. On the basis of this difference, Staff's view is that sales customers should pay for uncollectible gas costs, but transportation customers should not pay for uncollectible gas costs because neither North Shore nor Peoples Gas provide gas supply to transportation customers.

Staff notes that its witness Luth developed an uncollectible rate for each customer service classification that would result in the uncollectible rate for each customer service classification being applied to gas costs that each customer service classification is estimated to incur in the test year. Id. Sched. 19.3-NS and 19.3-PG. Thus, by developing a customer service classification-specific uncollectible rate, Staff contends that sales gas customers in each service classification would pay uncollectible gas costs that are based upon how customers in their own service classification affect uncollectible gas costs rather than how customers in other service classifications affect uncollectible gas costs. Staff claims to have demonstrated how the Companies' approaches yielded inconsistent results because a given customer service classification would pay different amounts for uncollectible gas costs, depending upon whether Rider UBA would be implemented or if uncollectible gas costs would be included in base rates. Id. at 16-17.

Staff argues that the Commission should reject both the proposed Rider UBA, and the Utilities' proposed alternative approach to including uncollectible gas costs in base rates. Instead, Staff urges the Commission to apply the calculations shown on Staff Schedules 19.3-NS and 19.3-PG, so that uncollectible gas costs are recovered from sales customers on a class-specific basis. The calculations that are shown on these schedules, Staff explains, would ensure that transportation customers in some customer service classifications do not overpay for natural gas delivery service while others pay less than the cost paid for natural gas delivery service compared to sales customers.

With respect to the Utilities' surrebuttal proposal to possibly bill uncollectible gas costs through the customer charge, Staff believes that under no circumstances should uncollectible gas costs be recovered through the customer charge. Gas costs are billed on a per-therm basis through the Rider 2 Gas Charge. Amounts uncollectible through therms billed under Rider 2 should not be included in the customer charge, Staff claims, because of the mismatch that would occur for amounts billed but uncollected on a per-therm basis, versus charging for the uncollectible amounts on a per-customer basis.

The Utilities' alternative proposal to recover gas costs through the distribution charge is generally appropriate and is generally in agreement with Staff's proposal, but the specifics of that proposal serve to overcharge some customers for uncollectible gas costs and do not sufficiently charge other customers. According to Staff, the defects in the Companies' proposal are perhaps most apparent with Peoples Gas SC 1N uncollectible gas costs. As such, Peoples Gas would recover $1,432,688 in uncollectible gas costs from SC 1N customers, PGL Ex. VG 2.3, column [C], line 2, but

total test year gas SC 1N costs are only $14,425,000, PGL Ex. VG-1.2, page 2 of 2, column [H], line 24. $1,432,688 divided by $14,425,000 total gas costs suggests an SC 1N uncollectible rate of 9.93 percent, but the rate of uncollectible SC 1N accounts in the test year was 5.92 percent. Staff Cross-Ex. 4 (Grace), page 3 of 3, column [D], line no. 9.

Staff notes that Peoples Gas has not explained why the SC 1N uncollectible gas costs rate is 1.677 times the overall SC 1N uncollectible rate by Staff's calculation (9.93 percent divided by 5.92 percent). Other customer classes at both North Shore and Peoples Gas also show differences in the overall uncollectible accounts rate and the uncollectible gas costs rate. The reduction in the transportation distribution rate and the increase in the sales distribution rate should be calculated according to the method recommended by Staff, Staff Ex. 19.0, Schedules 19.3-NS and 19.3-PG, rather than the method suggested by the Utilities (where uncollectible gas cost rates do not agree with the overall uncollectible rates applicable to each customer service classification).

c) AG

On reply brief, the AG joins the issue. Uncollectibles are a cost of doing business, the AG notes, and arguably should be spread to all rate classes in proportion to their overall percentage of the cost.

The AG observes that the Utilities' proposal, to allocate (1) 78.7% of the uncollectible expense to Rate 1 Heating customers, and (2) then allocate 67% of the rate 1 Heating customers allocated share to the first block volumetric charge, would *trigger a nickel increase to this per therm charge solely for gas cost uncollectible expense*. PG-NS Init. Br. at 160-62. This is inequitable, the AG argues, and should be rejected.

First, the AG notes, the proposal fails to recognize the Companies agreement to reduce the test year level of uncollectibles associated with gas costs by $3.3 million in accordance with Mr. Effron's proposed adjustment. *See* PGL-NS Ex. 2.3. Second, the AG argues, the proposed rate design exacerbates the inequities of bifurcating Rate 1 customers into separate rate categories and contributes to the rate shock Residential Heating customers stand to bear if the Companies rate design proposals are approved. In the AG's view, the Utilities' proposal in this regard deviates from the rate design goals of stability and gradualism, and highlights yet another reason to not bifurcate the residential rate class.

Third, the AG contends that the allocation of 67% of the residential allocation of uncollectible expense in the first per therm volumetric block is completely arbitrary. There is no support, the AG observes in either the ECOSS or the supporting workpapers for this first-block allocation. Further, the allocation is counter-intuitive to the notion that as usage increases, uncollectibles increase. Simply put, the higher the gas bill, the more likely bad debt increases. Thus, the AG argues, the Utilities' proposal to allocate 67% of the residential heating customers' allocated cost to this first volumetric block violates cost causation principles as well.

Fourth, the AG argues, allocating the lion's share of the cost to this first volumetric block sends customers the wrong price signals regarding usage of natural

gas, a nonrenewable energy source. This violates the rate design goal of conservation of resources. *See* GCI Ex. 1.0 at 7.

Instead of punishing residential heating customers with higher first block, per therm rates, and possibly contributing to increased, future uncollectible expense, the AG believes that the Commission should examine analyze this expense for rate design purposes in relation to revenues, consistent with the source of this expense. According to the AG, Schedule E-5, Section A, p. 1 provides a breakdown of revenues by customer rate class and could form the basis for allocation of the uncollectibles account expense related to purchased gas costs. (The Utilities' Rider UBA proposal trumpets the fact that the lion's share of uncollectibles costs rises as gas costs (and usage and revenues) rise.) The AG contends that this would have the effect of spreading the uncollectible expense associated with purchased gas costs across the customer rate classes. Further, the expense should be allocated on an equal percentage basis to the number of blocks within each rate class. This alternative to the Utilities' gas cost related uncollectible expense allocation, the AG argues, would satisfy the goals of gradualism, equity and fairness, conservation of resources.

In their exceptions arguments on brief, City-CUB joined in supporting the AG's position.

d) Commission Analysis and Conclusion

The Utilities and Staff address the issue of the appropriate recovery of gas cost related uncollectible expense for retail sales and transportation customers. The issue is relevant because the Commission does not approve Rider UBA. In this event, and because transportation customers do not ordinarily purchase gas from the Utilities, the gas cost related portion of uncollectible expense must be appropriately removed from the base rates.

We observe that both Mr. Luth and Ms. Grace would recover uncollectible expenses in the distribution rates. And, the respective method employed by the Utilities and Staff do not differ substantially. The Utilities believe that their method is simpler than that proposed by Mr. Luth. Nevertheless, we are informed that the Utilities would find Mr. Luth's methodology acceptable, if corrected to reflect test year gas costs and the appropriate revenues to be used in the determination of the credit for transportation customers' base rates. On this record, the Commission finds that the method for allocating gas cost related uncollectibles expense proposed by Staff is reasonable. That method will allocate the expense to Peoples Gas' S.C. Nos. 1N, 1H, 2 and 4 and North Shore S.C. Nos. 1N, 1H and 2. Further, the method should be supplemented by the corrections proposed by the Utilities.

The AG presents its views in an untimely fashion on Reply Brief. In their Brief on Exceptions, the Utilities responded to the AG's belated arguments, and the Commission finds that response persuasive. The AG's arguments are, essentially, an argument against the S. C. No. 1 rate design and not targeted to the question of the Account No. 904 expense. The Commission concluded the Utilities' S.C. No. 1 rate design was just and reasonable and, therefore, the AG's arguments are rejected.

Further exceptions arguments by City-CUB and the AG are not convincing.

C. Service Classification Rate Design

1. Uncontested Issues

a) North Shore Service Classification No. 4

(1) North Shore

The Company proposes to change the title of this service classification from "Contract Service" to "Contract Service to Prevent Bypass" so it is more descriptive. Also, it proposes to allow contract terms in excess of five years for this service classification and make minor editorial changes to the tariff language. NS Ex. VG-1.0 3REV at 23. No party or Staff opposes these proposals.

(2) Commission Analysis and Conclusion

The Commission finds the proposed changes to this service classification to be reasonable and these are accepted.

b) North Shore Service Classification No. 5

(1) North Shore

The Company's proposal is to set S.C. No. 5 at cost. Therefore, the monthly customer charge was set at $43.00. The monthly demand charge was set at 10.414 cents per therm and the distribution charge at 1.875 cents per therm. NS Ex. VG-1.0 2REV at 23. Based on his ECOSS, Staff witness Luth recommended that the Company's proposed monthly customer charge be reduced by 65 cents per month resulting in a monthly customer charge of $42.35. Staff Ex. 7.0 at 24. The Company accepts Mr. Luth's proposed adjustment as long as it is supported by the ECOSS approved in this proceeding.

(2) Commission Analysis and Conclusion

The Commission finds the proposal to set S.C. No. 5 at cost to be reasonable and the rates shall be set in accordance with the revenue requirement set forth in this Order.

c) Peoples Gas Service Classification No. 5

(1) Peoples Gas

Peoples Gas' sole proposal is to make minor editorial changes to the tariff language of SC No. 5. PGL Ex. VG-1.0 REV at 26. There has been no other proposal by Staff or by any party to this proceeding.

(2) Commission Analysis and Conclusion

The minor editorial changes proposed by the Company are here accepted.

d) North Shore Service Classification No. 6

(1) North Shore

North Shore's sole proposal is to make minor editorial changes to the tariff language of SC No. 6. NS Ex. VG-1.0 3REV at 24. There has been no other proposal by Staff or by any party to this proceeding.

(2) Commission Analysis and Conclusion

The minor editorial changes proposed by the Company are here accepted.

e) Peoples Gas Service Classification No. 6

(1) Peoples Gas

The Company's proposed changes are to set SC No. 6 at its embedded cost of service and to eliminate the distinction between heating and non-heating customers. The monthly customer charge was set at $90.00 or 80% of cost. The monthly demand charge was set at cost, 70.956 cents per therm, and the distribution charge at 14.878 cents per therm. PGL Ex. VG-1.0 REV at 26-27; NS-PGL Ex. VG-2.0 at 47-48. Staff witness Luth proposed to set S.C. No. 6 at cost although he did not make any specific rate proposals. NS-PGL Ex VG-3.0 at 27.

(2) Staff

Staff claims that the Companies Initial Brief errs in stating that Staff witness Luth did not have any specific SC 6 rate proposals. NS-PGL Init. Br. at 165. Staff agrees with the Companies' indication that Mr. Luth proposed to set SC 6 at cost, but in addition, Staff witness Luth presented SC 6 rates in his rebuttal testimony. Staff Ex. 19.0 at 20-21, Sched. 19.1-PG, p. 4 of 11, col. [F], lines 91-96; and p. 10 of 11, col. [F], lines 186-191. Staff notes that the demand charges shown for sales heating customers and transportation non-heating customers are annual rates which should be divided by 12 to arrive at a monthly charge. Id. Sched. 19.1-PG, p. 4 of 11, col. [F], lines 93-94; and p. 10 of 11, col. [F], line 190. Some of the demand charges are stated on an annual basis in part because SC 6 billing units in the Peoples Gas operating revenue schedules had been shown on an annual basis in direct testimony. NS-PGL Ex. VG-2.0 at 48. Rates for SC 6 should be set according to the cost of service developed through Staff's cost of service study, which includes the use of the A&P allocation factor for transmission and distribution system costs, adjusted to the test year revenue requirement authorized by the Commission.

(3) Commission Analysis and Conclusion

Based on what is before us, the Company's proposal to set S.C. No. 6 at cost and to eliminate the heating and non-heating distinction among S.C. No. 6 customers is reasonable and is accepted by the Commission. The rates shall be set in accordance with the revenue requirement set forth in this Order.

f) Peoples Gas Service Classification No. 8

(1) Peoples Gas

The Company proposes to increase charges under SC No. 8 to reflect its embedded cost of service. The monthly customer charge was set at $140.00 and the distribution charge was set at 5.022 cents per therm. PGL Ex. VG-1.0 REV at 27. Staff witness Luth proposed to set S.C. No. 8 at cost although he did not make any specific rate proposals. NS-PGL Ex. VG-3.0 REV at 27.

(2) Staff Reply Brief

Staff complains that the Companies Initial Brief errs in stating that Staff witness Luth did not have any specific rate SC 8 proposals. NS-PGL Init. Br. at 165. Staff agrees with the Companies' indication that Mr. Luth proposed to set SC 8 at cost, but in addition, Staff witness Luth presented SC 8 rates in his rebuttal testimony. Staff Ex. 19.0 at 20-21, Sched. 19.1-PG, p. 4 of 11, col. [F], lines 110-112. Rates for SC 8 should be set according to the cost of service developed through Staff's cost of service study, which includes the use of the A&P allocation factor for transmission and distribution system costs, adjusted to the test year revenue requirement authorized by the Commission.

(3) Commission Analysis and Conclusion

Staff's position is set out in its Reply Brief and has been considered. In these premises, we are compelled to find that the Company's proposal to set S.C. No. 8 at cost is reasonable and accepted by the Commission. The rates shall be set in accordance with the revenue requirement set forth in this Order. Staff's exceptions brief indicates no objection to our conclusion on the matter.

2. Contested Issues

a) Peoples Gas Service Classification Nos. 1N and 1H

b) North Shore Service Classification Nos. 1N and 1H

(1) Utilities

The issues pertaining to Service Classification Nos. 1N and 1H apply equally to Peoples Gas and North Shore. Therefore, they explain, the following discussion applies to both Companies.

In discussion under Section VII(B)(2)(c) hereof, the Utilities maintain that they have appropriately demonstrated a basis for bifurcating former Service Classification No. 1 into two service classifications, S.C. No. 1N and S.C. No. 1H. In this section, the Utilities discuss the specific S.C. No. 1N and S.C. No. 1H charges proposed by other parties, as well as certain S.C. No. 1N and S.C. No. 1H implementation proposals made by Mr. Luth.

North Shore has proposed to set its S.C. Nos. 1N and 1H at cost while Peoples Gas proposes to apply the EPEC methodology to allocate costs to S.C. Nos. 1N and 1H. The Utilities propose to establish the S.C. No. 1N charges for Peoples Gas and North Shore at $11.25 and $10.50, respectively. For Peoples Gas, the total monthly embedded fixed costs per customer, with Rider UBA, is $18.14 and the total monthly allocated cost per customer with Rider UBA, derived by applying the EPEC method, is $14.99. While the proposed $11.25 Peoples Gas charge represents 64% of embedded customer costs and 62% of total embedded fixed costs, the Utility explains that, by applying the EPEC method and only a portion of allocated customer costs, the increase has been limited to $2.25 per month in the interest of gradualism. Moving the charge to total allocated fixed cost would require an additional increase of $3.74 per month, while

moving the charge to total embedded fixed cost would require an additional increase of $6.89 per month.

For North Shore, the total monthly embedded fixed cost per customer with Rider UBA is $16.18. The proposed $10.50 charge represents 70% of embedded customer costs and 65% of total embedded fixed costs, North Shore has limited the increase to $2.00 per month in the interest of gradualism. Moving the charge to total embedded fixed cost would require an increase of an additional $5.68 per month. PGL Ex. VG-1.0 REV at 12; NS Ex. VG-1.0 2REV at 10.

Peoples Gas is proposing to increase the monthly customer charge for S.C. No. 1H from $9.00 to $19.00 and North Shore would increase S.C. No. 1H from $8.50 to $16.00. The total embedded fixed cost per customer with Rider UBA is $36.27 and the total monthly allocated fixed cost per customer, derived by applying the EPEC method, is $33.80. While the proposed $19.00 charge represents 71% of embedded costs and 52% of total embedded fixed costs, the Utility points out that, by applying the EPEC method and only a portion of allocated customer costs, Peoples Gas has limited the increase to $10.00 per month in the interest of gradualism. Moving the charge to total allocated fixed costs would require an additional increase of $14.80 per month, while moving the charge to a total embedded fixed cost would require an additional increase of $17.27 per month. If properly aligned, the Utility asserts, such charges would be recovered entirely through a fixed monthly charge. In the interest of rate design continuity, however, Peoples Gas is proposing to recover all demand costs, as well as remaining customer costs, through the distribution charge.

Similarly, the total embedded fixed cost per customer for North Shore is $29.28. While the proposed $16.00 charge represents 55% of total embedded fixed costs and 79% of embedded customer costs, North Shore has limited the increase to $7.50 per month in the interest of gradualism. Moving the charge to total embedded fixed cost would require an increase of an additional $13.28 per month. If properly aligned, such charges would be entirely recovered through a fixed charge such as the customer charge or a demand charge. In the interest of rate design continuity, however, North Shore is proposing to recover demand costs as well as remaining customer costs through the distribution charge. PGL Ex. VG-1.0 REV at 13-14; NS Ex. VG-1.0 3REV at 11-12.

Utilities note Mr. Glahn to propose that S.C. No. 1N not be bifurcated and that Peoples Gas decrease its customer charge to $10.50, while retaining the distribution charge in Peoples Gas' currently applicable declining block rate structure. They observe that Mr. Glahn's proposed customer charge represents a slight increase in the customer charge from $9.00 to $10.50. According to the Utilities, however, his S.C. No. 1 proposal is arbitrary as Mr. Glahn offers no analysis or justification for it, except for casually comparing it to the customer charges of other Utilities. As such, Mr. Glahn has not performed a cost study for the Utilities nor has he provided any analysis of the other utilities rate designs, costs underlying their rates, or any reasoned discussion of how they have been developed or how they specifically compare with Peoples Gas' rates or why such a comparison is relevant.

The Utility contends that Mr. Glahn's proposal for North Shore's S.C. No. 1 charge is similarly flawed. In short, he proposes no bifurcation of North Shore's S.C. No. 1 charge, establishing it at its current level of $8.50. According to the Utility, however, Mr. Glahn offers no analysis to support his customer charge proposal, and he makes no attempt to address the North Shore customer charge in relation to the other components of North Shore's rates, such as the distribution charge. The Utilities submit that Mr. Glahn's North Shore proposal is, at best, incomplete.

The Utility observes Staff witness Luth to propose that Peoples Gas slightly increase its proposed S.C. No. 1N in customer charge from $11.50 to $12.00. The Utility contends that it would not be opposed to this charge as long as any change in the distribution charge is reasonable. It notes too that Mr. Luth proposes that the increase in the S.C. No. 1N in customer charge be offset by a decrease in the distribution charge. And, he further proposes that Peoples Gas' S.C. No. 1H charge be set no higher than the Peoples Gas proposed $19.00 charge. According to the Utility, Mr. Luth makes no additional specific recommendations concerning Peoples Gas' S.C. No. 1H distribution charges other than to say that they should not be reduced as long as overall cost are not recovered by rates. Further, Mr. Luth does not propose any changes to North Shore's S.C. No. 1N.

The Utilities maintain that they have presented proposals for S.C. No. 1N and S.C. No. 1H rates that are comprehensive, detailed, and analytical. On the other hand, they argue, the rate proposals of Mr. Glahn are very general and not based on any cost studies or reasoned analysis.

In the Utilities view, Mr. Luth proposes very reasonable customer charges for Peoples and North Shore S.C. Nos. 1N and 1H. He also reasonably recommends that Peoples Gas' S.C. No. 1N distribution charges be reduced to offset the increase in the customer charge but makes no recommendation as to distribution rates for the Utilities' S.C. No. 1N.

According to the Utility, Mr. Luth proposes to reduce the distribution rates for North Shore's S.C. No. 1H as his ECOSS allocates fewer costs to S.C. No. 1H than North Shore's ECOSS. This would also be reasonable, the Utility asserts. But the Utility considers his proposal for Peoples Gas S.C. No. 1H distribution charge as being too general to warrant any consideration. Where the customer charge proposals of the Utilities do not differ significantly from Staff witness Luth's proposals, they maintain that the approval of the Utilities' comprehensive and well reasoned proposals for rates for S.C. No. 1N and S.C. No. 1H would amount to acceptance of a large part of the Staff proposal.

(2) Staff

Staff observes Peoples Gas to propose to bifurcate the present residential service classification ("SC") 1 into SC 1N and SC 1H. The distinction, Staff notes, is based upon the use of natural gas at the residential customer's service address. More specifically, the distinction is based upon for what use the natural gas is being used for, i.e., heat or non-heat. As such, Staff observes, SC 1N would apply to residential customers who do not use natural gas for space heating purposes, while SC 1H would

apply to residential customers who use natural gas for space heating purposes. The Utility-proposed rates under SC 1N would offer an $11.25 per month customer charge that is lower than the $19.00 per month customer charge under SC 1H, but a 49.77¢ per therm single, or flat-block usage charge, that is higher than the declining two-block usage charges of 35.220¢ and 10.768¢ per therm under SC 1H.

Staff does not necessarily oppose the separation of residential customers according to usage. But, it contends that the separation should be based upon volume, i.e., low usage vs. higher usage. In many, if not most cases, Staff believes that its proposed separation would have the same end result as the Utilities' proposal, based upon how natural gas is used (i.e. Heat or Non Heat) because space heating typically requires far more natural gas than non-space heating uses. In Staff's view, if a non-space heat customer uses sufficient volumes of natural gas such that a billing under SC 1N would exceed a billing under SC 1H, the non-space heat customer should not be forced to pay more than a SC 1H customer with comparable usage simply because the non-space heat customer does not use natural gas for space heating. If anything, Staff notes, the relatively high-use non-space heating customer should pay less than the heating customer for the same usage because the load profile for the non-heating customer should be expected to be more constant, thereby minimizing the need for extra capacity costs for service during demand peaks. Staff Ex. 19.0 at 9.

Staff's solution to non-space heating customers possibly qualifying for SC 1H rates is for the customer to be given a choice whether to be billed during the off-peak, summer months under SC 1N or SC 1H. Id. at 9-11. In Staff's view, customers should be advised of the opportunity to change how they will be billed for the next 12 months, and further advised that the choice will remain in effect until the following June 15th. According to Staff, the Utility would provide generic information to the customer to consider in making the choice between SC 1N and SC 1H, such as the break-even point for monthly usage where SC 1N billing becomes more expensive than SC 1H billing, and leave for the customer to consider how natural gas will be used over the next October 15th through June 15th period.

If the administrative challenge of providing residential customers a choice between SC 1N and SC 1H billing is overly burdensome to the Company, then Staff proposes that the cost of service and billing unit information for the proposed SC 1N and SC 1H customer classes should be combined to develop a set of rates for an SC 1 customer class. Currently, Staff notes, residential non-space heating and space heating customers are subject to the same rates for the same usage, so combining the two types of customers would not represent a change in how those customers are billed. At the Company-proposed revenue requirement, the lower customer charges with UBA suggested by Company witness Grace are acceptable to Staff if the proposal to separate SC 1N and SC 1H customers with UBA is rejected by the Commission. NS-PGL Ex. VG-3.0 at 12, table preceding line 247. Staff does not support Rider UBA, but it is not reasonable that a customer charge without Rider UBA would be higher than if Rider UBA is authorized by the Commission. The proposed Rider UBA is a per-therm charge, Staff explains, so the lack of Rider UBA should affect usage charges, but not the customer charge.

If the Commission approves the separation of residential customers into SC 1N and SC 1H, Staff recommends that rates be based upon its cost of service study. Staff proposed rates, it explains, would result in a subsidy from SC 2 customers of approximately $9.94 million, meaning that SC 1N and SC 1H customers would pay a combined $9.94 million less than cost of service at the Utility-proposed revenue requirement. Under Utility-proposed rates, Staff notes that SC 1N and SC 1H customers would pay $20.1 million less than cost of service at the Utility-proposed revenue requirement, and this would require a larger amount above cost of service from SC 2 customers. Staff is sensitive not only to rate increases affecting customers, but also to the amount customers pay relative to cost of service. Thus, in Staff's view, since SC 2 is being asked to pay for SC 1N and SC 1H costs in addition to SC 2 costs, SC 2 revenues above SC 2 costs should be minimized despite SC 1N and SC 1H revenues that would average approximately 44¢ per therm for delivery.

Staff notes CUB-City and the AG to object to the customer charges that Staff witness Luth proposed, which are based upon the Staff cost of service study results, the revenue requirements proposed by Peoples Gas and North Shore, and a customer charge that is lower than SC 1N and SC 1H customer costs. Staff Ex. 19.0, Sched. 19.2-NS, S.C. 1 Non-heating and S.C. 1 Heating col., *Amount (under) class cost of services*, Customer Charge Revenues line; and Sched. 19.2-PG, S.C. 1 Non-heating and S.C. 1 Heating col., *Amount (under) class cost of service*, Customer Charge Revenues line. Staff observes both CUB-City of Chicago and the AG to believe that the customer charges recommended by Mr. Luth are too high and should be lowered, consistent with the position outlined by their joint witness Glahn. Had Mr. Luth been a strict constructionist with a singular focus on recovering a class's cost of service, as the AG argues, Staff points out that the customer charge would have been more than what he proposed because SC 1N and SC 1H customer costs are not fully recovered through the proposed customer charges and distribution charges. Increased customer charges would have required SC 1N and SC 1H customers to pay more than proposed by Staff, even at the lower SC 1N and 1H cost of service Staff proposed compared to the Companies. Furthermore, a lower customer charge relative to class cost of service would have required either: 1) a higher distribution charge in the first usage block to recover a greater level of customer costs, or 2) an increased subsidy from another customer class to pay for the under-recovered SC 1N and SC 1H costs.

Increases to other customer service classifications are also high on a percentage basis under the revenue requirement proposed by Peoples Gas, such that Staff considers requiring further increases from these customers to fund SC 1N and SC 1H costs to be unreasonable. Staff Exhibit 19.0 at 18-19. It is seems possible to Staff, that a lower revenue requirement authorized by the Commission would make some increases less difficult. Staff believes, however, that SC 1N and SC 1H should move closer to cost of service, particularly when other customer classes are also facing significant rate increases. Id. at 19-20.

Staff contends that the Utilities are mistaken in claiming that Mr. Luth makes no recommendation on SC 1N distribution rates. NS-PGL Init. Br. at 169. Staff points out that Mr. Luth presented SC 1N distribution rates in his rebuttal testimony. Staff Ex.

19.0, Sched. 19.1-NS, p. 1 of 8, col. [F], lines 2-5 and 18-21; p. 4 of 8, lines 2-8 and 22-28; and Sched. 19.1-PG, p. 1 of 11, col. [F], lines 2-5 and 18-21; p. 5 of 11, col. [F], lines 2-5 and 22-28. These rates, Staff explains, are based upon the results of Staff's cost of study at revenue requirements proposed by North Shore andPeoples Gas, with a subsidy from SC 2 to SC 1N and SC 1H and having the effect of reducing SC 1N and SC 1H rates. Staff Ex. 19.0 at 18-20.

(3) City-CUB

i. Bifurcation of Peoples Gas S.C. No. 1

City-CUB maintain that the Utilities have not shown that there to be a significant difference in the cost of serving Peoples Gas S.C. 1 heating and non-heating customers or that bifurcation would reduce or eliminate any subsidy flowing between heating and non-heating customers. Thus, they argue, S.C. 1 should remain as a single class.

City-CUB note the Utilities to contend that, based on the ECOSS, there is a "significant difference in fixed costs" for heating and non-heating customers. Id. at 11. The testimony of GCI witness Glahn, however, observes that the ECOSS appears to assign an implausibly high portion of costs to heating customers relative to the costs assigned to non-heating customers. *See* GCI Ex. 3.0 REV. at 16. City-CUB explain that Mr. Glahn used a Peoples Gas work paper to calculate the average cost per customer of meters, regulators and services for Peoples Gas S.C. 1H and 1N customers, and he noted that the per-unit cost of regulators for non-heating customers is less than a third of the cost for heating customers, and that the per-unit cost of services for non-heating customers is approximately one-third the cost for heating customers. Id. at 16-17. He further explained that the allocation of service plant seems particularly implausible because the cost of installing services presumably would depend largely on labor and construction costs that "should vary little by the size of the pipe, at the sizes typically used for residential customers." Id. at 17. Additionally, City-CUB observe Mr. Glahn to have questioned whether the utility would dig up an old service and replace it with a larger one every time a non-heating customer decides to install a gas furnace and become a heating customer, or instead simply install from the beginning services that would accommodate a range of end uses. Id. at 7-11. In any event, City-CUB argue, the Utilities have not convincingly explained why there is such an apparently large disparity in the cost of services for heating and non-heating customers in S.C. 1.

In the City-CUB's view, the Companies' attempt to account for these differences adds more confusion rather than clarification. Mr. Amen's testimony, they note, discusses purported cost of service differences relating to whether the service being installed is used by a single customer or is shared by multiple customers. Specifically, Mr. Amend responded to Mr. Glahn, by stating that:

> Mr. Glahn's average per customer calculations for service plant fail to account for the occurrence of multiple S.C. No. 1 non-heating customers served by shared gas lines. This is the predominant characteristic for non-heating residential customers on Peoples Gas' system and not an uncommon industry practice where there are separately metered multi-

> family dwelling units served by a single service line and apartment units for other natural gas end uses. In fact, 97% of Peoples Gas' non-heating residential customers share a gas service line while almost half (47%) of the residential heating customers are served by a separate, dedicated service line.

NS-PGL Ex. RJA-2.0 at 15.

The City-CUB assert that the Utilities have failed to reconcile this testimony with Ms. Grace's account that, S.C. No. 1 includes only dwellings with two or fewer units. Tr. at 959 (Grace). If this is the case, Mr. Amen's explanation for the cost of service differential between S.C. 1 heating and non-heating customers is implausible. It seems highly unlikely, the City-CUB argue, that service costs vary significantly, i.e., by a 3-to-1 ratio, as calculated by Mr. Glahn, according to whether the service is used by one customer or is shared by two customers.

City-CUB note Mr. Amen to have testified that, a "relatively prevalent practice" in the gas distribution industry is to have two single-family dwellings share a single service. Tr. at 321. In such cases, he added, "the service line has enough capacity, generally speaking, that it doesn't require a larger service than it otherwise would to service a single customer," depending on the pressure system to which the service is connected. Id.

City-CUB assert that the apparent contradiction between the Utilities witness testimonies carries through to Mr. Amen's surrebuttal testimony, where he responds to Mr. Glahn's observation that the primary driver of cost of service differentials appears to be whether the customer is a residential single- or multi-family customer, or residential single- versus shared-service customers (whether the customer falls in S.C. 1 or another class), and not whether the customer is an S.C. 1 heating or non-heating customer. Specifically, Mr. Amen countered that the direct assignment of service plant to S.C. 1 heating and non-heating customers and the resulting cost differential properly reflects the design considerations of the services, which require larger services to be installed where multiple customers are connected to a single service with cumulatively larger connected peak loads as well as the length of those services. NS-PGL Ex. RJA-3.0 at 9-10.

Regardless of the precise meaning of the ambiguous term "multiple" in this testimony, City-CUB contend that it is problematic. If "multiple" means "more than two," then this is inconsistent with Ms. Grace's testimony regarding the types of customers included in S.C. 1. If "multiple" would just mean "two," Mr. Amen's testimony strains credulity and conflicts with his hearing testimony that oftentimes larger services are not required to serve two single-family dwellings. And, it is unclear to City-CUB whether Mr. Amen's observation that "[a]s a group, heating customers place a significantly higher peak load on the system than do non-heating customers" refers to all heating and non-heating customers or just heating and non-heating customers in S.C. 1. Id. at 8.

In the City-CUB's view, an approval of the bifurcation of S.C. 1 into heating and non-heating sub-classes cannot be had on the basis of a questionable cost of service differential that may, or may not apply, to heating and non-heating customers *in S.C. 1*.

The Utilities alone bear the burden of proof in this proceeding, *see* 220 ILCS 5/9-201(c), the City-CUB argue. And, in their view, the Utilities have failed to establish that the significant difference in the cost to serve S.C. 1 customers is due to a heating/non-heating distinction and not to the single/multiple family factor Mr. Glahn identified.

ii. Customer Charges for S.C. 1N and 1H

(a) Peoples Gas Proposal

Based on its proposal to bifurcate S.C. 1, City-CUB observe that Peoples Gas proposes to increase its customer charge for S.C. 1H customers from $9.00 to $19.00 per month – a 111 percent increase – and the corresponding charge for S.C. 1N customers from $9.00 to $11.25 per month. *See* PGL Ex. VG-1.4 at 2. They would have the Commission deny Peoples Gas's request in this regard based on Mr. Glahn's testimony that substantially higher customer charges for S.C. 1H customers would harm low- and fixed-income customers.

According to Ms. Grace, City-CUB note, Mr. Glahn fails to recognize that, customers' total bills do not necessarily increase if customer charges are increased because higher customer charges are offset by lower volumetric or distribution charges. NS-PGL Ex. VG-2.0 at 37. The reason that Mr. Glahn did not address total bill impacts, the City-CUB point out, is that such impacts are irrelevant to his fundamental point, i.e., low- and fixed-income customers are more adversely affected by higher fixed customer charges than higher distribution charges because the former charge, unlike the latter, cannot be managed through reducing consumption. *See* GCI Ex. 6.0 REV. at 12.

City-CUB further observe Ms. Grace to claim that, according to Peoples Gas' analysis, the average use for the "lowest income customers" is higher than the class average use per customer for S.C. No. 1H. NS-PGL Ex. VG-2.0 at 37-38. This analysis simply does not establish what she claims it does.

City-CUB note this analysis to compare the average use of households by zip code in Chicago with the various mean annual household income ranges for each zip code, the lowest range being $32,000 to $40,000. *See* NS-PGL Ex. VG 2.8-PGL. According to City-CUB, It does not reveal the average use of the lowest income customers, as Ms. Grace maintains; it shows the average use of customers residing in the zip codes with the lowest mean household income range. After all, that households in a particular neighborhood have a particular average income does not mean that the actual incomes of every – or any – household in that neighborhood is exactly the average income. Rather, as Ms. Grace admitted on cross-examination, average household income for a particular zip code suggests that the zip code includes households with incomes both higher and lower than the mean income. Tr. at 965. City-CUB observe that Peoples Gas's analysis does not identify the actual individual household incomes for a particular zip code, thus leaving unknown whether a zip code includes extreme highs or lows in household income that are not suggested by the mean household income.

Moreover, Ms. Grace's reliance on the conclusions of a witness regarding the relationship between usage and household income in another jurisdiction, Missouri, with distinct demographic, housing stock and other relevant characteristics does not cure the deficiencies in Peoples Gas's study. *See* NS-PGL Ex. VG-2.0 at 38. In fact, Peoples Gas's graph of average use for certain household income ranges, NS-PGL Ex. VG 2.8-PGL, does not remotely resemble the "U" shape relationship between usage and income described in the excerpt of the witness's testimony in the Missouri case quoted by Ms. Grace.

Assuming *arguendo* that Ms. Grace is correct about low-income customers' gas consumption levels, City-CUB maintain that this does not justify more than doubling fixed charges for S.C. 1 heating customers. Instead, the solution that both protects low-income customers, and (unlike the Companies' proposal to lower distribution charges) sends a proper price signal, is targeted energy efficiency assistance programs that provide low-income customers with weatherization and energy efficient appliance rebates to control gas usage. GCI Ex. 6.0 REV. at 13. City-CUB argue that Peoples Gas' proposal to lower distribution charges, is itself ground for rejecting its rate design proposals for S.C. 1N and 1H. Lowering volumetric charges, they assert, sends the wrong price signal, i.e., to consume more gas, and this results in violation of the AGA's "conservation of resources" rate design objective. *See* GCI Ex. 3.0 REV. at 7 & 31. Because increased consumption requires the burning of more natural gas, lowering volumetric charges also fails to meet the "environmental protection" rate design goal. *See id.*

Unable to refute these assertions, Ms. Grace attempts to minimize the anti-conservation effect of Peoples Gas's proposal to reduce volumetric charges, insisting that the gas cost portion of customers' bills sends "the appropriate signal on gas consumption." NS-PGL Ex. VG-2.0. This case, the City-CUB argue, does not concern the gas or commodity cost portion of customer bills or total bill impacts; it concerns the delivery services portion of bills, including the customer charge and the distribution charge. *See* PGL Ex. RJA-1.0 at 11. The undeniable fact is that, in proposing a fixed rate element and a consumption-related rate element for the distribution portion of the bill in this case, the Companies chose to lower the volumetric charge – the only distribution rate element that sends a price signal relating to consumption. And Ms. Grace's assertion that moving "more cost recovery to fixed charges enhances the price signal," (NS-PGL Ex. VG-2.0 at 39) – a signal that would not affect usage – fails to address the goal of encouraging conservation, a rate design objective that the Companies' proposals ignore. Accordingly, the Companies' proposed customer charges for S.C. 1N and 1H should be rejected.

In lieu of Peoples Gas' unreasonably high proposed customer charges for S.C. 1 heating and non-heating customers, the Commission should adopt Mr. Glahn's recommended S.C. 1 customer charges. Consistent with his recommendation to keep S.C. 1 whole, Mr. Glahn proposes setting the monthly customer charge for Peoples Gas S.C. 1 at no more than $10.50 – a 16.7 percent increase above the current level. If approved, Mr. Glahn's proposed customer charge for Peoples Gas S.C. 1 would require that the distribution charge for that class be adjusted to meet the revenue requirement

for Peoples Gas adopted by the Commission. Id. at 32. Mr. Glahn's proposed increase in customer charges would increase Peoples Gas's recovery of fixed costs through fixed charges, but without placing an undue hardship on smaller customers, including in particular low- and fixed-income customers. *See* GCI Ex. 3.0 REV. at 31-32.

As shown in GCI Ex. WLG -3.1, Sched. 6, City-CUB assert that Mr. Glahn's proposed customer charges would be comparable to the customer charges for similar rate classes of other Illinois investor-owned natural gas utilities. This favorable comparison does not establish, as Ms. Grace would have it, that Mr. Glahn "arbitrarily set" his proposed customer charge based on the customer charges of other Illinois utilities. To the contrary, Mr. Glahn's Direct Testimony made clear that Mr. Glahn developed his proposed customer charge for S.C. 1 to achieve rate design objectives such as social goals and stability that Peoples Gas's proposals utterly fail to meet. That Mr. Glahn's proposed charges – unlike Peoples Gas's – are comparable to those of other LDCs regulated by the Commission merely indicates that they share a rate design philosophy the Commission has accepted as reasonable for such fixed charges. *See* GCI Ex. 3.0 REV. at 27-33. Nor is there merit to Ms. Grace's claim that Mr. Glahn's proposed Peoples Gas S.C. 1 customer charge is not "cost based," (NS-PGL VG-2.0 at 35) Mr. Glahn recommends increasing the customer charge to increase recovery of fixed costs, just not at the pace proposed by Peoples Gas, a pace that would unduly burden small residential customers. Thus, Mr. Glahn's proposal is properly based on cost as well as other established rate design criteria.

(b) Staff Proposal

City-CUB urge the Commission to not adopt Staff witness Luth's proposed customer charges for S.C. Nos. 1N and 1H because, in their view, these fail the same rate design criteria as the Utility's proposal. For Peoples Gas, they note, Mr. Luth would increase the customer charge for S.C. 1N customers from $9.00 per month to $12.00 per month, a 33.3 percent increase that is even higher than Peoples Gas's proposed $11.25 monthly charge, and increase the S.C. 1H customer charge to $19.00 per month, just as the Utility has proposed. Staff Ex. 7.0 at 25-26. Like Peoples Gas's proposal, City-CUB assert, Staff's recommendations are narrowly focused on moving rates closer to full cost recovery and fail to take account of the impact of substantially increasing customer charges on small residential ratepayers, and particularly, low- and fixed-income customers. GCI Ex. 6.0 REV. at 16-17.

iii. North Shore

For the reasons discussed in section IX.C.2.a. above with respect to Peoples Gas S.C. 1, the Companies' proposal to bifurcate North Shore S.C. 1 into heating and non-heating sub-classes should also be rejected.

With respect to customer charges, City-CUB note that North Shore proposes increasing its monthly customer charge for S.C. 1H from $8.50 to $16.00 per month (an 88 percent increase) and to increase the corresponding charge for S.C. 1N customers from $8.50 to $10.50 per month. NS Ex. VG-1.4 at 2. For the same reasons that City-

CUB dispute proposed increases in Peoples Gas's customer charges, they maintain that proposed customer charges for North Shore should be rejected. In this instance too, City-CUB argue, the Commission should adopt Mr. Glahn's recommendation to keep North Shore S.C. 1 whole, and to maintain the existing $8.50 monthly customer charge for that class. This recommendation, they assert, is based on the position of GCI witness David Effron that North Shore's overall revenue requirement should be reduced. Keeping the North Shore S.C. 1 customer charge at the current level while reducing total revenues for the utility, they argue, would increase the proportion of fixed costs recovered through fixed charges, consistent with the Utilities' stated goal in this case. GCI Ex. 3.0 REV. at 34; *see also* NS Ex. VG-1.0 REV. at 7.

(4) AG

The AG maintains that the Utilities' proposal, to bifurcate the residential Rate 1 class, produces a significantly higher customer charge proposal for Peoples and North Shore heating customers, as compared with their Non-heating Rate 1 customers. And, the AG observes, their proposed residential rate design also includes *lower* per therm distribution charges.

GCI witness Glahn noted that while the customer charge for Peoples is increasing at a triple digit rate, the volumetric charges are falling by more than 8 percent for volumes over 50 therms. PGL Ex. VG-1.4. Similarly, with respect to North Shore, while the customer charge is increasing by 88 percent, the volumetric charges are falling by a significant 45 percent for volumes over 50 therms. NS Ex. VG-1.3.

When reviewing these proposed rates, Mr. Glahn the Commission should keep a number of points in mind. First, any increase in a rate element of more than 100 percent constitutes rate shock and, consequently, fails all tests for "gradualism," notwithstanding Utilities' witness Grace's assurances to the contrary. GCI Ex. 3.0 at 30. Second, the Companies are proposing no mitigation measures, such as a multi-year phase-in. Id.

The AG observes Mr. Glahn to have testified that sharply higher fixed costs "fall disproportionately on those least able to pay," thereby failing the "social goals" test. Id. Moreover, he indicated that a proposal that would have some elements increase dramatically, while other rate elements fall dramatically, fails the "stability" test. Id. at 31. In addition, having volumetric rate elements decrease sends the wrong price signal, given the Companies' claims that overall costs for Peoples and North Shore have increased by more than $100 million and more than $6 million, respectively. Id. In addition, lowering distribution charges discourages conservation efforts, failing the "conservation of resources" test, another rate design objective referenced by Mr. Glahn. Id. Lowering volume charges fails the "environmental protection test" as well, given the fact that the actual burning of natural gas produces negative environmental impacts. Id.

The AG maintains that the concept of "social goals" in rate design is important when considering residential customers. Mr. Glahn noted that low income and fixed income customers fall disproportionately into the Heating subcategory. Id. at 19-21. Thus, the AG contends, the proposed $19 fixed customer charge imposes a significant burden upon low-income households in the Chicago area, and represents more than

four percent of their monthly income. Id. at 14. And, unlike distribution charges, the AG points out, customer charges cannot be mitigated by reducing usage. According to the American Gas Association, "(s)ocial ratemaking goals involve rate designs that advance the welfare of a particular group in society." Id. at 21. For persons on fixed incomes, "higher utility prices may mean a significant decrease in well-being," according to the AGA. Id.

Illinois' seasonal prohibition on gas company shut-offs supports Mr. Glahn's assertion that the provision of affordable utility service is an important social goal. Similarly, the aforementioned requirement in the Public Utilities Act that rates be "least-cost" confirms Mr. Glahn's position. It is noteworthy that "social goals" were not among the goals stated by Utilities' Grace in describing the Companies' rate design objectives.

Staff witness Luth, apparently a strict constructionist when it comes to following ECOSS, recommended imposing customer charges that are even higher than the Companies propose. For Peoples Gas' residential Non-heating customers, Mr. Luth recommended the customer charge increase *beyond the level proposed by the Company* from the current $9.00 per month to $12.00 per month, a 33 percent increase that is higher than the $2.25 increase proposed by Peoples. ICC Ex. 7.0 at 25, 26. For Peoples' heating customers, Mr. Luth concurs with the Company's proposal to increase the customer charge by 111 percent to $19.00. Id.

For North Shore, Mr. Luth endorsed the customer charge proposals proposed by the Company for both Heating and Non-heating customers. Id. at 20. Mr. Luth's rationale for supporting (and increasing) the customer charges proposed by the Companies amounts to a concern that "customer costs are under-recovered by the proposed customer charges." Id. at 25. Despite his acknowledgement during cross-examination that gradualism is one of the goals of rate design, Tr. at 1464, 1465, nowhere are the rate design concepts of gradualism or social goals mentioned within his singular focus on recovering a class's cost of service. In fact, he recognized that "a $10 increase might impact some people hard, yes." Tr. at 1469.

As the Commission ponders the cost allocation and rate design dilemma, along with the competing views as to whether and to what degree residential customer charges need to be increased, it is helpful to re-examine Bonbright's views on the matter. What is clear is that the residential customer charges proposed by the Companies are excessive, and not aligned with legitimate principles of rate design.

In order to correct the inequities and satisfy the aforementioned rate design goals, Mr. Glahn proposed that the monthly customer charge for all Peoples Gas customers be set at no more than $10.50. Id. The $10.50 amount represents a $1.50 or 16.7 percent increase over the current level. Id. In conjunction with that rate, he proposed that the volumetric charge would then be adjusted to achieve the needed revenue requirement, based on the level of revenue increase ultimately awarded to Peoples Gas. Id. at 32. Mr. Glahn clarified that his proposal would maintain the current distribution charge design. This includes retaining the current two-block rate design distribution charge for non-heating customers. Id.

For North Shore's residential customers, Mr. Glahn recommended that the monthly customer charge for both heating and non-heating customers be retained at the current $8.50 level, based on GCI witness Effron's conclusion that the Company's overall revenues should be reduced. Id. at 34. He noted that keeping this rate element the same, while reducing overall revenues, increases the amount of fixed costs collected through fixed charges. Id. Mr. Glahn's recommended customer charges, after adjusting the corresponding volumetric charges appropriately, would allow both Companies to fully recover their revenue requirements. Id. at 10.

As a point of comparison, the AG notes, Mr. Glahn examined the customer charges for similar rate classes found at Illinois' other investor-owned natural gas utilities. His Exhibit WLG 3.1, Schedule 6, attached to GCI Exhibit 3.0, contains a comparison between the fixed monthly charges and volumetric charges for residential and small commercial customers for these various utilities. Mr. Glahn's proposed Peoples Gas customer charge falls in the middle of the charges listed, and would exceed the level charged by Illinois Power Company and Nicor Gas Company. Id. at 33.

The Companies' proposal to increase Peoples Gas Rate 1 Heating customer charges for Peoples Gas and North Shore customers by 111% and 88% should cause the Commission to keep a number of points in mind. First, any increase in a rate element of more than 100 percent constitutes rate shock and, consequently, fails all tests for "gradualism," notwithstanding the Companies' assurances to the contrary. GCI Ex. 3.0 at 30. Second, the Companies are proposing no mitigation measures, but rather suggest that these proposals satisfy notions of gradualism and rate design continuity. PGL-NS Brief at 163, 167. This assertion simply cannot be taken seriously.

The AG urge the Commission to look beyond claims of a need for strict, fixed cost recovery when designing rates, especially since the record shows that the Companies *have* recovered their fixed costs in the past when rates supposedly recovered only 30% of fixed costs through fixed charges. PGL-NS Brief at 163. The Companies proposed customer charges are excessive, and not aligned with legitimate principles of rate design.

In order to correct the inequities and satisfy the aforementioned rate design goals, Mr. Glahn proposed that the monthly customer charge for all Peoples Gas customers be set at no more than $10.50. Id. The $10.50 amount represents a $1.50 or 16.7 percent increase over the current level. Id. In conjunction with that rate, he proposed that the volumetric charge would then be adjusted to achieve the needed revenue requirement, based on the level of revenue increase ultimately awarded to Peoples Gas. Id. at 32. Mr. Glahn clarified that his proposal would maintain the current distribution charge design. This includes retaining the current two-block rate design distribution charge for non-heating customers. Id.

For North Shore's residential customers, Mr. Glahn recommended that the monthly customer charge for both heating and non-heating customers be retained at the current $8.50 level, based on GCI witness Effron's conclusion that the Company's overall revenues should be reduced. Id. at 34. He noted that keeping this rate element the same, while reducing overall revenues, increases the amount of fixed costs

collected through fixed charges. Id. Mr. Glahn's recommended customer charges, after adjusting the corresponding volumetric charges appropriately, would allow both Companies to fully recover their revenue requirements. Id. at 10.

As a point of comparison, Mr. Glahn examined the customer charges for similar rate classes found at Illinois' other investor-owned natural gas utilities. His Exhibit WLG 3.1, Schedule 6, is attached to this Brief as Appendix B, and contains a comparison between the fixed monthly charges and volumetric charges for residential and small commercial customers for these various utilities. Mr. Glahn's proposed Peoples Gas customer charge falls in the middle of the charges listed, and would exceed the level charged by Illinois Power Company and Nicor Gas Company. Id. at 33.

Mr. Glahn's common-sense approach to designing rates is superior to the Companies' proposals, which are guided solely by their continuing quest to ensure margin revenue and fixed cost recovery. A customer charge of no more than $10.50 satisfies the goal of gradualism, while still contributing to increasing the portion of fixed costs recovered in the customer charge. Moreover, it satisfies the social goals that have guided this Commission's rate-setting practices in the past, which includes some subsidization for the residential class and avoidance of rate shock. Finally, increasing the distribution charges sends customers the correct price signals, which include a recognition that increased usage can result in the need for system expansions and defeat the goal of conserving resources. Id. Mr. Glahn's proposed rate design for the residential class should be adopted.

(5) Utilities Response

The Utilities note the GCI parties to argue that the bifurcation has not been justified and should be rejected, while Staff urges that if the bifurcation is approved, a procedure is needed permitting customers to annually elect the classification under which to receive service. For their part, the Utilities' bifurcation proposal is based upon the significant cost differential between small residential heating (S.C. No. 1H) and non-heating (S.C.No.1N) customer classifications and the appropriate designation of accounts based upon utility information, practices and analyses. NS-PGL Init. Br. at 165-169.

According to the Utilities, Staff does not oppose bifurcation *per se*, but would base it upon volume, i.e., high usage versus low usage, instead of their heating versus non-heating distinction. And, Staff would apply its annual customer election features in either case.

The Utilities further observe Staff to indicate that, if its proposed annual customer election feature is considered to be administratively challenging or burdensome, the Utilities should consider developing rates for a non-bifurcated service classification which would collapse proposed S.C. No. 1N and 1H into a single S.C. No. 1. Staff also indicates that it would find acceptable a customer charge developed by Ms. Grace at the Utility's proposed revenue requirement with Rider UBA if the Commission does not approve Rider UBA. *See* Staff Init. Br. at 236. As such, Staff implicitly agrees with the Utilities' approach to developing a S.C. No. 1 customer charge if the Utility's bifurcation proposal is not approved. Staff, however, proposes that a lower customer charge be

based on a revenue requirement with Rider UBA, even if Rider UBA is not approved. According to the Utilities, it would be more logical and more consistent that the Commission accept a customer charge that is aligned with the approved revenue requirement. Thus, the Utilities outline, the customer charge should be based on the revenue requirement without Rider UBA (if Rider UBA is not approved), and with Rider UBA (if Rider UBA is approved). If the Commission is put to choose between the Utilities' bifurcation proposals and Mr. Luth's "customer election" proposals, which would adversely impact the Utilities as well as customers, the Utilities would prefer a customer charge using its proposed approach. *See,* NS-PGL Ex. VG-3.0 at 16.

The Utilities maintain their position that their proposed bifurcation for S.C. No. 1H and S.C. No. 1N is justifiable and should be approved and not complicated by the Staff's convoluted and overwhelmingly problematic annual election proposal. No such enhancement is necessary, they claim, because it would impose a level of complexity and confusion into the process that is not warranted. The Utilities contend to have demonstrated and, it is unrebutted, they argue, that reliable and fairly comprehensive data exists to justify bifurcation along heating and non-heating lines. The Utilities further assert that they conducted a cost study analysis which demonstrates that heating customers create significantly higher system costs than non-heating customers. While Mr. Luth made a vague reference to a volume based bifurcation model, the Utilities maintain that he offered no reasoning or data to support why volume should be the basis for bifurcation.

In opposition to the Utilities' bifurcation proposal, they observe the AG to make a series of unconnected and partially applicable claims. For example, the AG asserts that an increase of 100% "in a rate element" - - i.e., in any part of a bill such as a single charge -- constitutes rate shock. AG Init. Br. at 137. The Utilities contend that the AG's argument is exaggerated given that it only focuses on the Utilities' proposed customer charges for S.C. No. 1H and completely ignores the offsetting decreases in the proposed distribution charges.

According to the Utilities, the AG attempts to couch its criticism in theoretical constructs. As such, AG urges that the Utilities' increases "fall disproportionately on those least able to pay", thereby failing a purported, "social goals test". Id. It is basic, the Utilities point out, that any rate increase of any kind will affect those with less ability to pay but, they argue, the AG has made absolutely no showing to support its claim of "disproportionality." Further, the Utilities note that following the AG's line of reasoning, any rate increase would fail its "social goals test", i.e., a test which has no legal force but is merely one principle, among many, some contradictory and inconsistent, which are posited by a theoretician, Dr. Bonbright. On the other hand, Peoples Gas maintains that it has proven that low-income customers tend to consume gas at levels higher than the class average and that its proposed rate design would be more favorable to such customers than the lower customer charge, higher distribution charge rate design that would arise from Mr. Glahn's proposal. Similarly, North Shore's rate design would be favorable for low-income customers during the winter period when gas prices are typically higher. *See* NS-PGL Ex. VG-2.0 at 37-39 & 43.

While the Utilities observe the AG to refer to a "conservation of resources" test and an "environmental test" with the claim that these also fail because lowering distribution charges discourages conservation and causes negative environmental impacts. AG Init. Br. at 137-138. The Utilities maintain however, that gas costs, which are the most significant portion of a customer's bill, provide the appropriate test. *See* NS-PGL Ex. VG-2.0 at 29. According to the Utilities, the AG's reference to theories and purported tests is highly selective and would create the impression that its favored goals are paramount in rate design. In their view, a reasonable rate design must incorporate goals that are considerably more even handed and broadly applicable.

To this end, the Utilities assert that the testimony of Ms. Grace points out that the they have proposed rates and rated designs that incorporate many of the theoretical principles, including social goals, that typically apply in rate design. She also notes that there is no requirement that rate designs must meet all theoretical rate design objectives or that such a feat is even possible. Even Mr. Glahn acknowledges that there are often conflicts among rate design objectives. The Utilities have sought to employ sound rate design principles and other measures that they believe are most appropriate and reflect their interests of all customers and customer groups. As such, they argue, the Commission must disregard false and irresponsible assertions such as the suggestion that the Utilities have "fudged their cost apportionments by using the category of customer costs as a dumping ground for costs that they cannot plausibly impute to any other costs categories." AG Init. Br. at 149. No such allegation or implication can be found on the record or otherwise regarding the Utilities' rate design proposals.

The Utilities consider the AG's intent is to preserve an unwarranted rate design advantage for residential customers to be well apparent from Mr. Glahn's proposal to set the monthly customer charges for Peoples Gas at $10.50 and $8.50 for North Shore. Mr. Glahn proposes these customer charges in an almost casual manner. He offers absolutely no cost analysis or justification to support them, aside from broad references to customer charges of other Illinois utilities, never analyzing or explaining how their costs structures require that their resulting rates should in any way apply to the Utilities. In short, Mr. Glahn's customer charge proposals are superficial, not well reasoned and completely unsupported by any cost or rate analysis. They appear to be purely outcome driven. This Commission, the Utilities argue, should not endorse such a careless and parochial approach to designing customer charges and the proposals of the AG must be denied.

City-CUB engages in similar end-results oriented pleading to advocate unreasonably low customer charges. City-CUB makes several of the same claims as AG that despite all clear reasoning to the contrary, lower customer charges must be preserved to protect the interests of one group of customers – low and fixed income rate payers. In the final analysis, the Utilities argue, City-CUB has offered no more persuasive reasoning in support of Mr. Glahn's proposals.

The Utilities contend that they have each presented proposals for S.C. No. 1N and S.C. No. 1H rates that are comprehensive, detailed and analytical. In contrast, they

argue, the rate proposals of Mr. Glahn are very general and not based on any cost studies or reasoned analysis.

The Utilities further observe that Mr. Luth proposes very reasonable customer charges for Peoples and North Shore S.C. Nos. 1N and 1H. And, he also reasonably recommends that Peoples Gas' S.C. No. 1N distribution charges be reduced to offset the increase in the customer charge. He makes no recommendation as to distribution rates for North Shore and Peoples Gas' S.C. No. 1N. Mr. Luth proposes to reduce the distribution rates for North Shore's S.C. No. 1H as his ECOSS allocates fewer costs to S.C. No. 1H than North Shore's ECOSS. This would also be reasonable. However, his proposal for Peoples Gas S.C. No. 1H distribution charge is too general to warrant any consideration. Where the customer charge proposals of the Utilities do not differ significantly from Staff witness Luth's proposals, the Utilities contend that approval of their comprehensive and well reasoned proposals for rates for S.C. No. 1N and S.C. No. 1H would amount to acceptance of a large part of the Staff proposal.

(6) Commission Analysis and Conclusion

The issue is whether to implement a bifurcation between S.C. Nos. 1N and 1H as the Utilities have here proposed. Having reviewed the evidence, the Commission concludes that bifurcation of S.C. No. 1 into two service classifications would be reasonable, but it has concerns about both the Utilities' and the Staff's proposals. Staff witness Luth has included proposals for implementing an election procedure and he would differentiate the proposed S.C. No. 1H and S.C. No. 1N customers based on small volume vs. larger volume instead of the Utilities' heating vs. non-heating distinction. These are each interesting proposals in their own way. In the end, however, the Commission believes that Mr. Luth's proposal to establish bifurcation along volumetric lines is somewhat vague and insufficiently detailed to permit full consideration. And, his customer election proposal brings up unnecessary problems. The Commission agrees with the Utilities that the introduction of annual elections for service classifications would result in unwarranted complexity and it would bring about customer confusion. Further, the Commission is unable to ascertain precisely what benefits would be obtained by customers switching service classifications without a reasonable and appropriate reason for doing so. At the same time, however, Mr. Luth has raised valid concerns about the impact of the Utilities' proposal on those non-heating customers who may have relatively high usage in a given month. While there appear to be a small number of customers falling into this category, the Commission agrees with Mr. Luth that they should not pay a higher rate than if they were on S.C. No. 1H. Accordingly, the Commission does not adopt the Utilities' proposed bifurcation. In its place, the Utilities have proposed a rate design to retain a single service classification for small residential customers. The Commission finds this proposal, including the method for setting the customer and distribution charges, to be a reasonable alternative to bifurcation of S.C. No. 1.

The Commission also concludes that the embedded cost of service study is the most appropriate means of assigning costs to S.C. Nos. 1N and 1H and the application of the EPEC method, in conjunction with the cost study, generates rates that properly reflect a greater recovery of fixed costs as the Commission believes is appropriate. In

considering Mr. Glahn's approach, we find it inconsistent and outside the goals of increasing fixed cost recovery. As we see it, Mr. Glahn's proposal would generate rates using the filed revenue requirement that are substantially below those proposed by the Utilities. It is difficult to evaluate in full the propriety of Mr. Glahn's proposal because it is unaccompanied by sufficient analysis or justification in the form of a cost study or some other measure. While the Commission is sensitive of the need to balance social goals with other objectives in its rate design determination, we do not believe the parties opposing the Utilities' proposal have demonstrated that the Utilities have employed anything less than the settled broad objectives of rate design, including social goals, in the S.C. No. 1N and S.C. No. 1H proposals at hand.

In the final analysis and with these same considerations in mind, the Commission believes that the Utilities' proposed alternative to bifurcation represents the most reasoned approach to establishing just and reasonable rates for small residential heating and non-heating customers. Specifically, the Commission rejects proposals to bifurcate S.C. No. 1 and adopts: the Utilities' alternative proposal to retain a single service classification for small residential customers; the Utilities' proposed customer charges for both Utilities' S.C. No.1 classification to be set at 50% of the revenue requirement for S.C. No. 1; the Utilities' proposals for calculating the distribution rates, including a declining two block rate; Peoples Gas' use of the EPEC method; establishing North Shore's S.C. No. 1 distribution rate using the methodology described in NS-PG Ex. VG-3.0 at pages 20-21.

c) Peoples Gas Service Classification No. 2

d) North Shore Service Classification No. 2

These issues have been merged.

(1) Utilities

Peoples Gas proposes to increase the monthly customer charge for S.C. No. 2 customers and to move the charges for meter classes one and two closer to embedded cost for each individual meter class, instead of considering an average of the embedded customer cost for all S.C. No. 2 customers. Under its proposal, monthly customer charges would increase from $15.00 to $21.00 for Meter Class 1 and increase from $22.00 to $60.00 for Meter Class 2. These charges, Peoples Gas maintains, are supported by the ECOSS. Peoples Gas is also proposing to maintain the three declining block distribution charge for SC No. 2 and to allocate 23%, 61% and 16% of the remaining customer, demand and commodity costs to the front, middle and end blocks, respectively.

According to Peoples Gas, the front block charge has been increased to 35.441 cents, the middle charge has been increased to 13.669 cents per therm and the end block has been decreased to 7.199 cent per therm. The proposed S.C. No. 2 charges exclude the gas cost portion of uncollectible expenses, which would be recovered through Rider UBA. Without Rider UBA, the proposed customer charges would remain the same but the front, middle and end block charges would be 37.695 cents per therm, 14.5339 cents per therm and 7.655 cents per therm, respectively. PGL Ex. VG-1.0 REV at 22-23.

Mr. Glahn proposes to increase Peoples Gas' Meter Class 1 customer charge to $27.00 so that it "matches" a charge for one utility and "falls in the midst" of certain other utilities. On the other hand, Peoples Gas notes that Mr. Glahn selectively avoids any comparison for Meter Class 2 as Peoples Gas' proposed rate at $60.00 is less than the $70.00 and $90.00 rates charged by those certain other utilities. According to Peoples Gas, Mr. Glahn's proposals are based on arbitrary, inapt comparisons and not on sound ratemaking principles.

North Shore proposes to increase the monthly customer charge for S.C. No. 2 customers and move the charges for Meter Classes 1 and 2 closer to the embedded cost for each individual meter class, instead of considering an average of the embedded customer cost for all S.C. No. 2 customers. The proposed monthly customer charges would increase from $15.00 to $17.00 for Meter Class 1 and from $22.00 to $60.00 for Meter Class 2. The proposed customer charges are less than the embedded fixed cost for each meter type and are supported by the ECOSS. North Shore is proposing to also maintain the three declining block S.C. No. 2 distribution charge and allocate 25%, 55% and 20% of the remaining customer demand and commodity cost to the front, middle and end blocks respectively. The front block increases to 23.248 cents per therm, the middle block decreases to 8.716 cents per therm and the end block decreases to 2.769 cents per therm. The proposed S.C. No. 2 rates for North Shore do not include the gas cost portion of uncollectible expense which is recovered through Rider UBA. Without Rider UBA the monthly customer for North Shore would mostly remain the same and the front, middle, and end block charges would be 24.175 cents per therm, 9.064 cents per therm, and 2.879 cents per therm, respectively. NS Ex. VG-1.0 3REV at 19-20.

The Utility notes Mr. Glahn to propose that the North Shore S.C. No. 2 customer charges not be increased. In its view, however, he offers no reasoned analysis or other detail to support his proposal. Thus, the Utility argues, Mr. Glahn's S.C. No. 2 recommendations are arbitrary and without merit.

Although Peoples Gas does not agree with Mr. Luth's undefined rate increase methodology for S.C. No. 2, it notes that his rate design proposals are consistent with those proposed by Peoples Gas. As to North Shore's S.C. No. 2, however, there appears to be some divergence of opinion between Mr. Luth and North Shore.

Mr. Luth proposes to change North Shore's S.C. No. 2 demand device and transportation administrative charges. Those charges, are cost based and rider specific for North Shore's proposed transportation Riders AGG, SST and P, irrespective of a customer's service classification. According to the Utilities, it is not appropriate to adjust rider specific charges simply to meet a particular service classification's revenue requirement. If North Shore's S.C. No. 2 needs to be adjusted to meet its revenue requirement, the Utilities consider that it would be more appropriate to adjust charges that are applicable to the service classification, rather than a charge designated in several riders that applies to several service classifications. NS-PGL Ex. VG-3.0 REV at 23.

(2) City-CUB

City-CUB observe Peoples Gas to propose increasing the monthly customer charge for its S.C. No. 2 Meter Class 1 from $15.00 to $21.00 or a 40 percent increase. For its S.C. No. 2 Meter Class 2, they point out that the Utility seeks an increase from $22.00 to $60.00 – a 173 percent increase. *See* PGL Ex. VG-1.4, p. 2. As Mr. Glahn noted, however, any increase in a rate element of more than 100 percent "constitutes rate shock, and thus fails all tests for 'gradualism,' despite assurances from Ms. Grace to the contrary." GCI Ex. 3.0 REV. at 30. To avoid imposing rate shock on S.C. 2 customers – particularly Meter Class 2 customers – and to meet the rate design objective of gradualism, Mr. Glahn recommends limiting the new customer charge for Meter Class 1 to no more than $19.00 – 26.6 percent above the current level. Id. at 32. This charge, the City-CUB contend, would match the comparable customer charge for MidAmerican and "fall in the midst of the other comparable [Illinois] utilities' rates." Id. at 34. For Meter Class 2, Mr. Glahn recommends limiting the new customer charge to $27.00 or 22.7 percent over the current charge. This proposed charge is higher than that of MidAmerican and somewhat below the comparable charges of some Illinois utilities with two-tiered rates, but it is appropriate given Peoples Gas's declining block structure for volumetric charges. Id. at 34; *see also* GCI Ex. 3.1, Sched. 6. Assuming Mr. Glahn's recommendations were approved, City-CUB note that the corresponding volumetric charges would need to be adjusted to achieve Peoples Gas's approved revenue requirement. Id. at 32.

According to City-CUB, Mr. Glahn's comparison of his proposed customer charges to those of comparable Illinois utilities is not the only bases for his proposal. NS-PGL Ex. VG-2.0 at 44. Mr. Glahn's recommended customer charges for S.C. 2 are designed to avoid rate shock and to comport with gradualism, *see* id. at 29-34; and that the resulting charges also happen to fall within the range of such charges imposed by other Illinois utilities merely demonstrates that they fall within a reasonable range. NS-PGL Ex. VG-2.0 at 44.

City-CUB observe that North Shore proposes increasing the monthly customer charge for its S.C. No. 2 Meter Class 1 from $15.00 to $17.00. And, North Shore seeks to increase the customer charge for Meter Class 2 from $22.00 to $60.00 or a 173 percent increase. *See* NS Ex. VG-1.3 at 2. Based on GCI witness Effron's recommended reduction to North Shore's revenue requirement, and to avoid imposing rate shock on S.C. 2 customers, Mr. Glahn recommends retaining the respective $15.00 and $22.00 charges for Meter Classes 1 and 2. Keeping this rate element the same while reducing the utility's overall revenues would increase the proportion of fixed costs recovered through fixed charges – one of the Companies' stated goals in this proceeding. *See* NS Ex. VG-1.0 REV. at 7.

(3) AG

The AG charts the Utilities proposed customer charges for Rate 2 General Service and notes that the Companies' proposal would increase the Rate 2, Meter Class 2 customer charges by 173 percent. According to the AG, this amounts to rate

shock and violates any notion of gradualism. For his part, Mr. Glahn proposed that any approved increase in the Companies' revenue requirement should be allocated by increasing the customer charge for Meter Class 1 General Service customers to no more than $19.00, an increase of $4.00 or 26.6 percent from current levels. GCI Ex. 3.0 at 32. For meter class 2, Mr. Glahn recommended limiting the customer charge increase to $5.00, which would produce a $27 monthly charge, or a 22.7 percent increase from the current level. Id. Like his recommendations for residential distribution charges, the volumetric charge would then be adjusted to achieve the needed revenue requirement, based on the level of revenue increase or decrease ultimately awarded to the Companies. Id.

The AG asserts that Mr. Glahn's proposed Rate 2 customer charges satisfy the goal of gradualism, while still contributing to increasing the portion of fixed costs recovered in the customer charge. These should be adopted by the Commission.

The AG notes the Companies to criticize these proposals as arbitrary because Mr. Glahn observed that they "fall in the midst" of certain other utilities' Rate 2 customer charges. Indeed, comparison of other utilities' rates was considered legitimate, as discussed below, for the Companies' proposed Dishonored Check fee. Mr. Glahn's proposal should be adopted by the Commission.

(4) Commission Analysis and Conclusion

The Commission considers the Company's proposal to be the most reasonable means to design the S.C. No. 2 rates. Mr. Glahn's proposal lacks sufficient analysis. If not arbitrary, in making other utility comparisons for meter class 1, it is at times inconsistent, by not applying this approach to meter class 2. While gradualism is certainly a goal, it may overshadowed by other equally important considerations. We seriously question why Mr. Glahn proposes to limit the increase to the S.C. No. 2 customer charges to such a degree that they would remain far below the fixed costs for this service classification. Mr. Luth's proposal to change the S.C. No. 2 demand device and administrative charges is not defended on Reply Brief and does not appear to be based on any cost basis or other persuasive reasoning. On the whole, the increases proposed by the Utilities are shown to be warranted. While Mr. Luth's proposal to change the S.C. No. 2 demand device and administrative charges would result in proper cost recovery, we decline to adopt his proposal at this time because the demand device and administrative charges apply to other service classifications a well as S.C. No. 2. On the whole, the increases proposed by the Utilities are shown to be necessary. The exceptions of City-CUB and the AG do not persuade us otherwise.

e) North Shore Service Classification No. 3

(1) Utilities

North Shore's current S.C. No. 3 is a cost based rate that serves large volume, high load factor customers. The Utility inform us that present rates include a monthly two block demand structure which is set at 5,000 therms and over 5,000 therms. North Shore proposes to increase the front block to 10,000 therms to better reflect the higher monthly demand volumes that are representative of this service classification. The

minimum, average and maximum monthly demand volumes for this service classification are 19,000 therms, 26,000 therms and 34,000 therms, respectively.

The current demand block structure, which current data show is set too low, results in 19% of demand volumes falling within the first block and 81% of demand volumes falling in the end block. This does not allow North Shore to recover its demand costs through a reasonable rate design that accurately reflects the customer profile. To remedy this, at least partially, and to allow a more balanced cost recovery, the Company proposes to increase the front block to 10,000 therms. This would result in 38% of demand volumes falling within the first block and 62% of demand volumes falling within the second block. The revenue from S.C. No. 3 will be set at embedded cost as determined in the ECOSS. This is consistent with the rate treatment in North Shore's last rate case. NS Ex. VG-1.0 3REV at 21-22.

The demand charge will be set at 80% of cost, with 50% being recovered through the front demand block. That results in about 75% of the total S.C. No. 3 revenue requirement being recovered through the demand charges. The front block (0-10,000 therms) demand charge will be set at 49.065 cents per demand therm and the end block (over 10,000 therms) demand charge will be set at 30.574 cents per demand therm. The monthly customer charge will be set at cost and will be $705.00. The monthly standby service charge will be set at 11 cents per therm of standby demand with the remaining revenue being recovered through the distribution charge, which will be set at .262 cents per therm. Id. at 22.

Staff witness Luth proposes to allocate $236,527 more costs to S.C. No. 3 based on his use of the Average and Peak methodology over the amount that North Shore proposed. While he does not propose any changes to the customer charge, he is proposing to recover 23.1% of the S.C. No. 3 demand costs through the distribution charge resulting in an increase in the proposed S.C. No. 3 distribution charge to 0.46 cents per therm. Applying this proposed rate to the S.C. No. 3 distribution volumes results in distribution charge revenue of $85,246, which is only $36,693 higher than what North Shore proposed. A comparison of this amount to Mr. Luth's additional $236,527 of proposed S.C. No. 3 costs, results in an under-recovery of S.C. No. 3 costs of approximately $199,800.

According to North Shore, Mr. Luth failed to account for these additional costs in his revenue adjustments for S.C. No. 3. In addition, North Shore proposed to recover only 80% of demand related costs in the demand charge, with the remaining demand and commodity costs being recovered through the standby service charge and the distribution charge. This proposal is very similar to what Mr. Luth is proposing, but Mr. Luth used a different cost allocation methodology. As Mr. Luth agrees with North Shore's proposed customer charge and derives a demand charge which is similar to that proposed by North Shore, the distribution charge would need to be adjusted to appropriately recover the revenue requirement arising from his ECOSS. The charges would also need to be adjusted to reflect revenues arising from the standby service charge that was corrected. NS-PGL Ex. VG-2.10. Based on that correction, the standby service charge would be reduced from 11 cents per therm to 7 cents per therm.

Even with the proposed changes, all charges would need to be supported by the final ECOSS arising from this proceeding. NS-PGL Ex. VG-2.0 at 46-47.

Mr. Luth does not address North Shore's S.C. No. 3 in his Rebuttal Testimony although Staff Ex. 19.0, Schedule 19.1-NS accompanying that testimony reflects different demand and distribution charges than those proposed in his Direct Testimony and in data responses. Otherwise, Mr. Luth's customer charge proposal approximates that proposed by North Shore. NS-PGL Ex. VG-3.0 REV at 26. Given the lack of clarity attending Mr. Luth's proposals for North Shore's S.C. No. 3 charges, the Commission should adopt the Company's proposal which appears not to differ greatly from Mr. Luth's recommendations

(2) Commission Analysis and Conclusion

The Commission accepts the Company's S.C. No. 3 proposal. Staff noted, in its brief on exceptions, that the rates it developed for SC 3 were not sufficiently different from rates that would result from the Company's rates to warrant an objection.

f) Peoples Gas Service Classification No. 4

(1) Utilities

The Company's current S.C. No. 3 is a cost based rate that was designed to serve large volume, low load factor customers. The Company's current S.C. No. 4 is a cost based rate that was designed to serve large volume, high load factor customers. In the Company's last rate case the average load factors for S.C. No. 3 and S.C. No. 4 were 42% and 75%, respectively. Currently, these load factors are 37% and 51%, respectively. As the difference in average load factors has significantly narrowed between the two service classifications, Peoples Gas maintains that it is no longer necessary to provide service under two separate large volume service classifications. Combining these two service classifications under S.C. No. 4, Large Volume Demand Service, is also supported by the Company's ECOSS which demonstrates that on a per demand therm basis, there is very little difference in costs.

The revenue from S.C. No. 4 will be set at embedded cost for S.C. Nos. 3 and 4 combined as determined in the ECOSS. This is consistent with the rate treatment in the Company's last rate case. The monthly customer charge will be set at cost and will be $565.00. The demand charge will be set at 80% of cost, with 70% being recovered through the front demand block. That results in about 59% of the total S.C. No. 4 revenue requirement being recovered through the demand charges. The monthly standby service charge will be set at 24 cents per therm of standby demand with the remaining revenue being recovered through the distribution charge, which will be set at 1.211 cents per therm. The front block (0-7,500 therms) demand charge is 50.609 cents per demand therm and the end block (over 7,500 therms) demand charge is 40.163 cents per demand therm.

Currently, S.C. No. 3 customers are not required to have a daily demand measurement device to determine billing demand although S.C. No. 4 customers are required to have such a device. As the Company is proposing to increase the amount of the revenue requirement being recovered through the demand charge, these

customers will be required to have a daily demand device to determine billing demand. This should have a minimal impact on most S.C. No. 3 customers as about 90% of the current customers already have such devices installed. For those customers who do not have a daily demand device installed, until such device can be installed, the billing demand will be calculated using the same methodology currently used to make such a determination for transportation customers.

The sales customers' standby demand will be the same as their billing demand and the Rider SST customers' standby demand will be their selected standby demand. The Company would propose the same charges as those with Rider UBA. PGL Ex. VG-1.0 REV at 24-26.

Using his ECOSS, the Utilities note that Mr. Luth's proposal would results in only 33% of demand costs being recovered through the demand charge. This shifts 60% of demand cost recovery through a volumetric distribution charge with 7% of demand costs being recovered through the standby service charge. Mr. Luth's ECOSS shows volumetric commodity costs for Peoples Gas' S.C. No. 4 of $804,826 while his proposal results in recovery of $9.1 million or 1,119% over the amount that should be recovered on a volumetric basis. Mr. Luth expresses concern about Peoples Gas' increased demand charge for former S.C. No. 3 customers but overlooks the impact that his higher distribution charge would have on all customers. Mr. Luth's proposal would more than triple the distribution charge for current Peoples Gas' S.C. No. 4 customers. Mr. Luth's proposed rate designs, which are not based on sound ratemaking principals, would be uneconomical to customers in this service classification and may induce some to switch to S.C. No. 2 or bypass Peoples Gas' system. Conversely, Peoples Gas' proposals are reasonable and based on sound ratemaking principals.

(2) City-CUB

City-CUB maintain that tor the reasons they discussed in section IX.B.1., above, Allocation of Rate Increase, the rates for Peoples Gas S.C. 4 should be adjusted to move the class from 96 to 116 percent of the class's cost of service. And, rates for Peoples Gas S.C. 3, which the Companies propose to combine with People Gas S.C. 4, should be set at 107 percent of cost. *See* GCI Ex. 3.1, Sch. 2.

(3) Commission Analysis and Conclusion

The Commission accepts the Company's proposal to combine Rate 3 and 4, noting that we have not been presented with any persuasive evidence why the two service classifications should remain separate in view of the convergence of load factors that has been demonstrated. Staff in its exceptions indicated that at this stage of the proceeding it was no longer contesting this issue. Further, City-CUB have not set out an effective or meaningful analysis for their proposals.

g) Peoples Gas Service Classification No. 7

(1) Peoples Gas

Peoples Gas' current S.C. No. 7, Contract Service, is available to any customer for whom bypass of the Company's gas distribution system is economically feasible and

practical. PGL Ex. VG-1.0REV at 27. The Company proposes to change the description of this services classification from "Contract Service" to "Contract Service to Prevent Bypass" to make it more descriptive and allow for a longer term contract in response to customer requests. Id. at 27. No parties have contested those issues.

Peoples Gas considers Mr. Glahn's proposal to allocate costs to S.C. No. 7 to be flawed. First, the Company observes that it is rooted in his belief that Peoples Gas "assumes that the costs to service this group of customers has not increased since 1995." GCI Ex. 3.0 REV at 13. Peoples Gas explains that its present tariff limits contract terms for customers served under this service classification to five years. As a result, it contends, contracts which may have been in place since Peoples Gas' last rate case over eleven years ago have been renegotiated based on the proper cost considerations. And, Peoples Gas' allocation has been performed against the backdrop of the circumstances presently in place in respect of the contracts, i.e., data which has changed since 1996. Furthermore, Mr. Glahn never explained how any rate increase he might impute into rate design could be factored into the binding contracts that are currently in effect and that may expire up to five years from the effective date of Peoples Gas' increase. Accordingly, the Company urges that Mr. Glahn's proposed allocations for S.C. No. 7 be rejected by the Commission and Peoples Gas' proposed changes be approved.

(2) Staff

Staff considers the issue to be uncontested between Staff and the Company. According to Staff, the Company proposed to change the title of this service from "Contract Service" to "Contract Service to Prevent Bypass" to be more descriptive. The Company also proposed to allow a contract to extend longer than the current maximum of five years, i.e., a maximum of up to ten years. Also, the Companies proposed minor editorial changes. PGL Ex. VG-1.0 2REV at 27. Staff witness Harden found all of the Company's proposed changes to be acceptable. As set out in her testimony: (1) the changes are very minor with the exception of the change from a 5-year contract to a 10-year contract, (2) the increase in the length of the contracts would allow any costs that might be associated with the contracts to be spread out over a longer period of time and (3) a longer contract also saves the cost of the time it takes to negotiate a new contract between the parties. Staff Ex. 9.0 at 6.

(3) AG

On reply, the AG responds to the criticism of Mr. Glahn's proposal to allocate costs to S.C. No.7, the service classification formerly known as Contract Service, and the argument that he does not explain "how any rate increase he might impute into rate design could be factored into the binding contracts that are currently in effect" and may expire after the effective date of the Peoples Gas rate increase. PGL-NS Init. Br. at 176.

According to the AG, the Companies' argument ignores the fact that Mr. Glahn is not suggesting that Peoples has to charge S.C.7 a certain rate based on the allocation. Whether the Companies elect to recover these additional costs from S.C.7 customers is up to the Companies. GCI Ex. 6.0 at 9. The AG's concern is that, despite being

grouped with S.C.6 and 8, S.C. 7 is allocated none of the increase because, according to Ms. Grace, the revenues from S.C.7 are based on negotiated, contract rates. Id. at 13 (*citing* PGL Ex. VG-1.0 at 8). Mr. Glahn correctly noted that regardless of how prices are determined for members of S.C. 7, there is a cost to serve these customers. These customers use the same system facilities and services as all of the other S.C. customers. Id. at 8. Peoples provided no evidence that there is no cost to serve these customers. Some of the increases in costs that the Company alleges has occurred should be imputed to S.C. 7 customers. Such imputation corresponds with the other allocations to customer classes proposed by Mr. Glahn. As such, his recommendation in this regard should be adopted.

(4) City-CUB

City-CUB maintain that for the reasons discussed in section IX.B.1. above, 26.6 percent (the average system increase) of Peoples Gas's proposed rate increase should be apportioned to Peoples Gas S.C. 7. *See* GCI Ex. 3.1, Sch. 2.

(5) Commission Analysis and Conclusion

The Commission recognizes that S.C. No. 7 is a classification under which all rates are contractually based and individually negotiated. This service classification has been renamed, with the approval of Staff, to clarify that it is intended to address bypass concerns. We see no reason to effectively penalize the Company by attributing costs to the service which the utility might not be able to recover. As such, the Commission finds Mr. Glahn's proposal to be unwarranted under the whole of the circumstances. The exceptions of City-CUB and the AG restate earlier arguments and are not persuasive.

D. Tariffs – Other Tariff Issues

The Utilities have proposed certain changes in a variety of tariffs and for various reasons. None of the intervening parties have opposed any of the changes to the Tariff issues set out in this section, with the exception of the AG, and City-CUB, who oppose the $25.00 NSF charge. Staff, however, has objected to the language in some of these Tariffs. All but two of the objections have been resolved.

1. Rider 2, Factor TS

a) Utilities

The Utilities propose to revise Rider 2 to reflect the applicability and the renaming of applicable transportation riders. They also propose to eliminate Factor TS, Transition Surcharge and refund or recover any dollars awaiting recovery or refund through Factor NCGC, Non-Commodity Gas Charge. Staff witnesses Kahle and Harden support the Utilities proposal to roll Factor TS balances into their non-commodity gas charges. Staff Ex. 9.0 at 24; Staff Ex. No. 21.0 at 2-3. Given that no other parties have addressed this matter, the Utilities maintain that this proposal is uncontested.

b) Staff

Staff recognizes that the Companies have proposed changes to Rider 2 to reflect the applicability of the rider based on their proposal to eliminate and rename applicable

transportation riders. NS Ex. VG-1.0 3REV at 31 and PGL Ex. VG-1.0 2REV at 35. The proposed changes that refer to other riders are appropriate in Staff's view, if the Commission approves the elimination and renaming of certain transportation riders. Staff Ex. No. 9.0 at 25.

The Companies' propose to eliminate Factor TS – Transition Surcharge, and refund or recover any dollars awaiting recovery or refund through Factor NCGC – Non-Commodity Gas Charge. NS Ex. VG-1.0 3REV at 31; PGL Ex. VG-1.0 2REV at 35. Staff recommends the Commission approve the Companies' proposed elimination of Factor TS language in Rider 2 if the Commission approves Staff's recommendation to roll Factor TS balances into their non-commodity gas charges. Staff Ex. 21.0 at 10.

According to Staff, Rider 2 also reflects minor editorial changes to clarify language and pursuant to the Commission's Order in Docket 06-0540, and reflects the change to a calendar year for its fiscal year. NS Ex. VG-1.0 3REV at 31–32 and PGL Ex. VG-1.0 2REV at 35-36. Staff points out that, In Docket 06-0540, the Companies requested approval to change reconciliation years in the Gas Companies' Riders 2 and 11 to calendar year bases. And, the Commission approved the request at page 64 of its Final Order in that docket. Staff Ex. 9.0 at 24.

c) Commission Analysis and Conclusion

The Commission accepts the Utilities' proposal to revise Rider 2 to reflect the applicability and renaming of applicable transportation riders. Also, we accept the proposal to eliminate Factors TS, Transition Surcharge, and refund or recover any dollars awaiting recovery or refund through NCGC, Non-Commodity Gas Charge.

2. Charge for Dishonored Checks and/or Incomplete Electronic Withdrawal

a) The Utilities

The Utilities propose to increase their charge for dishonored checks and incomplete electronic withdrawals from $10.00 to $25.00 to better reflect prevailing rates for such checks and transactions and to discourage customers from making deficient payments to the Company. PGL Ex. VG-1.0 REV at 32. They note that the Commission has approved an increased charge of $25.00 for Mid American Energy in Docket No. 99-0534. And, the Utilities observe the Mid American Order to state that the increase "would serve to discourage payment with checks that are not valid" and "that revenues from this charge will serve to reduce the rates of those customers who make valid payments." Re MidAmerican Energy Company, 2000 WL 3444650, Docket No. 99-0534, Order (July 11, 2000).

In these proceedings, as in MidAmerican Energy, the Utilities contend that revenue from the Utilities' charge will offset the increase in base rates in this proceeding. PGL Ex. VG-1.0 at 32. They further point out that Staff witness Harden is supportive of the Utilities' proposal. Staff Ex. 9.0 at 11. Only GCI witness Glahn opposes the increase in the charge for dishonored checks and incomplete electronic withdrawals, basing his opposition on a lack of a cost study. GCI Ex. 6.0 REV at 15; GCI Ex. 3.0 REV at 35. The Utilities consider that this Commission was clear when it

approved a similar increase in the MidAmerican Energy Order to better reflect prevailing rates and to discourage customers from making deficient payments to the company. As Staff agrees, the Commission should approve the increase for dishonored checks and incomplete electronic withdrawals.

b) Staff

Staff agrees with the Utilities that the proposed increase in revenues from this fee will offset the increase in base rates in this proceeding and that MidAmerican Energy has raised the same fee to $25 as well, based on the Commission's approval in Docket 99-0534. Staff Ex. 9.0 at 10-11. Staff witness Harden further agreed with the Commission's position in the MidAmerican Energy case, i.e., that the increase in the fee would discourage customers from writing bad checks. Id. at 11.

c) The AG

The AG notes the Companies to rely on the charge authorized in the MidAmerican Energy case as support for the fee increase. PGL-NS Init. Br. at 178. Moreover, the Companies maintain that the new fee would serve to discourage payment with checks that are not valid. Id. at 177 (*citing* PGL Ex. VG-1.0 at 32; NS Ex. VG-1.0 at 28, 29). The Companies also assert that the increased charge will "offset the increase in base rates in this proceeding." Id. at 178.

GCI witness Glahn testified that this significant increase in fees is without cost support, which serves as a useful starting point and is an indispensable reasonableness check on rates. GCI Ex. 3.0 at 35. In response to an AG data request seeking support for the proposed fee, the Companies indicated that they performed no analyses, research or other studies with respect to the $25 fee. *See* GCI Ex. 3.1, Schedule 7. Accordingly, Mr. Glahn recommended that the Commission retain these charges at current levels until they provide a reasonable cost basis to support them. Id.

Addressing Mr. Glahn's challenges, the AG observes Utilities witness Grace to have stated that the Companies' proposed $25 fees "reflect the prevailing rates for such checks and transactions" and "the need to deter such payments." PGL-NS Ex. VG-2.0 at 52-53. And, the Company referenced a similar charge in the MidAmerican Energy case as further support for the fee increase. Id. According to the AG, however, the Companies data request response detailed in Schedule 7 of Mr. Glahn's direct testimony reveals that typical returned check fees "fall well below the $25 level proposed by the Companies and, in some instances, well below the $10 fee currently charged. Id. at 15 (*citing* GCI Ex. 3.1, Schedule 7).

In the AG's view, the record evidence does not support the Companies request to increase this fee by more than 66 percent. The Commission should retain the Companies $10 fee for dishonored checks, as recommended by Mr. Glahn.

d) City-CUB

The Companies propose to increase the charge for dishonored checks and/or incomplete electronic withdrawal from $10.00 to $25.00. PGL Ex. VG-1.0 REV. at 32-33; NS Ex. VG-1.0 REV. at 28-29. Because the Companies have failed to provide a cost basis for their proposal, it should be rejected.

According to the Companies, the proposed $25.00 charge reflects "the prevailing rates for such checks and transactions" and would "discourage customers from making deficient payments to the Companies." Id. Conspicuously absent from this assertion is any reference to the actual costs the utilities incur in dealing with dishonored checks or incomplete electronic withdrawals. *See* City-CUB Init. Br. at 121; GCI Ex. 3.1, Sched. 7. Instead, the Companies' proposal appears to be based on the eight-year-old MidAmerican Energy case and Staff witness Harden's Direct Testimony in this case, which cites the MidAmerican Energy case as the sole basis for her endorsement of the utilities' proposal. *See* Staff Ex. 9.0 at 11; *see also* Staff Init. Br. at 241. Because there is no cost basis in this record to support the proposed $25 charge, the charge for dishonored checks and incomplete withdrawals should be maintained at its current level. *See* City-CUB Init. Br. at 121.

e) Commission Analysis and Conclusion

The Commission finds the arguments of GCI witness Glahn unpersuasive. As pointed out by both the Utilities and Staff, this Commission has previously approved an increased charge of $25.00 in MidAmerican Energy. Id. at 716-17. Our rationale in MidAmerican Energy set out that, the increase "would serve to discourage payment with checks that are not valid" and "that revenues from this charge will serve to reduce the rates of those customers who make valid payments." The Commission is not made aware of any good reason to abandon, in this instance, the logic that drove our result in the MidAmerican Energy case. Nothing set out in City-CUB's exceptions is persuasive on the issue.

3. Rider 4, Extension of Mains

a) The Utilities

The Utilities propose changes to Rider 4 to clarify language and to address certain practices and customer preferences. The basic structure of Rider 4 is unchanged. The Companies are responsible for the costs associated with certain main installations as Part 500 of Commission's Rules provides. In those instances where, for example, a customer requests that the Companies install a main in a different location than is required to provide service, the customer would bear the incremental costs associated with meeting the customer's preferences. PGL, Ex. VG-1.0 REV at 36. Staff witness Harden disagreed with the language of Rider 4 regarding "return" and testified that the proposed language should not be approved for Rider 4. Staff Ex. 21.0 at 4-5. The Utilities maintain that they have conceded to the objection of Staff witness Harden and agree to remove the proposed language regarding "return." NS-PGL Ex. VG-3.0 REV at 29. No other parties addressed this matter and therefore, this matter is not contested.

b) Staff

Staff informs that under the Utilities proposal, the basic structure of Rider 4 is unchanged as it delineates the Companies and customer responsibilities. While certain language changes being proposed were acceptable to Staff, other changes caused its witness Harden some concern.

Staff witness Harden found the proposed language to be very broad and that it refers to charging customers, with no limit, for labor costs, material costs, transportation costs, overheads and return. Staff requested additional support and/or explanation for proposed language changes to Rider 4. Staff Ex. 9.0 at 26-27. Staff was not satisfied by the additional information in the Companies' rebuttal testimony (NS-PGL Ex. VG-2.0 at 53) and Staff continued to object to the proposed language of a "return" being charged to customers through Rider 4. Staff Ex. 21.0 at 5. In surrebuttal testimony, however, the Companies agreed to remove the "return" language from the Rider. NS-PGL Ex. VG-3.0 at 29. With the removal of "return" from the proposed language Staff states that its prior concerns are now satisfactorily addressed.

c) Commission Analysis and Conclusion

The Commission accepts the Utilities' proposed changes to Rider 4 as modified to address Staff's concern, i.e., removal of the language regarding "return." In all other respects the matter is uncontested.

4. Rider 5, Gas Service Pipe

a) Utilities

The Utilities propose to revise Rider 5 to clarify language and to address certain practices and customer preferences. The Utilities propose to reduce the free main extension shown in Rider 5 from 100 feet to 60 feet consistent with an agreement between Staff and parties related to questions raised by the Commission when it initiated Docket No. 03-0767. PGL Ex. VG-1.0 REV at 36. As with Rider 4, Staff witness Harden disagreed with the language of Rider 5 regarding "return" and, on this basis, recommended the language not be approved by the Commission. Staff Ex. 21.0 at 6. As with Rider 4, the Utilities agreed to concede to the objection of Staff witness Harden and remove the proposed language regarding "return". NS-PGL Ex. VG-3.0 REV at 29. No other parties addressed this matter and therefore, it is not contested.

b) Staff

Staff tells us that, in their surrebuttal testimony, the Companies agreed to remove the "return" language from the Rider. NS-PGL Ex. VG-3.0 at 29. With the removal of "return" from the proposed language, Staff's prior concerns in the matter were satisfactorily addressed.

c) Commission Analysis and Conclusion

The Commission accepts the Utilities' proposed changes to Rider 5 as modified to address Staff's concern, which removes the language regarding "return."

5. Rider 8, Heating Value of Gas Supplied

a) Utilities

The Companies propose to revise Rider 8 to reflect the applicability of the rider based on the elimination and renaming of transportation riders and to make a minor grammatical change. The revisions also specify that the Utilities will make filings only when the heating value factor changes, rather than file every month. PGL Ex. VG-1.0 REV at 37. Staff witness Harden opposes the Utilities' change regarding monthly filing

requirement believing there would be no assurance that the Utilities are reviewing heating value factors. Staff Ex. 21.0 at 8. The Utilities contend that they review heating values on an ongoing basis in the due course of their business, not simply on a monthly basis. They explain that the heating value factor often remains the same for two or more consecutive months, and a filing is only needed when the factor changes. PGL Ex. VG-1.0 REV at 37. The Utilities believe it appropriate that filings be made only when there is such a change.

b) Staff

Staff notes that the Companies proposed changes to Rider 8 to reflect the applicability of the rider based on their proposal to eliminate and rename applicable transportation riders. NS Ex. VG-1.0 3REV at 33 and PGL Ex. VG-1.0 2REV at 37. The proposed changes that refer to other riders are appropriate, Staff asserts, if the Commission approves the elimination and renaming of certain transportation riders. Staff Ex. No. 9.0 at 30.

In its testimony, Staff discussed the proposed revision by the Companies to make filings regarding the heating value factor only when the heating value factor changes, rather than every month, which is the existing practice. Staff Ex. 21.0 at 6-8. The heating value factor is discussed in Administrative Code Section 500.280(a)(1) Heating Value and Calorimeter Equipment which, in part, states:

> Each utility furnishing natural gas, liquified petroleum gas or a mixture of such gases with manufactured gas shall maintain in each community or territory served by it a monthly average standard of heating value of gas authorized by the Commission for that utility and community. Such standard of heating value shall be maintained with as little deviation as practicable, and the average total heating value on any one day shall not exceed or fall blow the authorized monthly standard by more than five percent.

Staff explains that the Companies currently file an information sheet and calculation sheet(s) showing any Btu adjustment that may be necessary each month. This monthly filing, Staff contends, gives assurance to the Commission that the heating value factor numbers have been reviewed by the Companies each month and that the standard heating value, as discussed above, is being maintained. Staff notes that the Companies' proposed tariff language change is a simple wording change from "each" month to "a" month, but Staff does not recommend that it be approved by the Commission. Similarly, Staff does not recommend approval of the proposed addition of the phrase "*and remain in effect until superseded by a subsequent filing pursuant to this rider*."

The basis for Staff's position is that if a filing is only required when there is a change in the heating value, this will not provide assurance to the Commission that heating value factors are being reviewed each month. If several months go by and no filing is made, Staff contends that the Commission has less assurance that the Companies are reviewing heating value factors; whereas if a filing is made each month, then the Commission receives assurance that the heating value factors have, in fact,

been reviewed by the Companies. Staff Ex. 21.0 at 6-8. Noting that the Companies did not respond to Staff's concerns in their surrebuttal testimony, Staff is unsure as to whether this is a contested issue.

c) Commission Analysis and Conclusion

We agree with the concern expressed by Staff Witness Harden regarding the need for assurance that the Utilities are reviewing heating value factors on an ongoing basis. The Utilities have shown no reason why the practice of monthly filings should not continue. We adopt Staff's recommendations in this instance.

6. Elimination of Riders 12, 13, 14, 15, CCA, and LCP

a) Utilities

Staff witness Harden agrees with the Utilities' proposed elimination of Riders 13, 14, 15, CCA, and LCP. Staff Ex. No. 9.0 at 18-21. No other parties addressed these matters, which leaves them uncontested.

b) Staff

The Companies proposed to eliminate People Gas' Rider 13 – Remote Meter Reading Devices; North Shore Rider 14 and Peoples Gas' Rider 15 – Taxes on Use of Compressed Natural Gas; Peoples Gas' Rider LCP – Low Income Customer Assistance Program; and both Companies proposed to eliminate Rider CCA – Customer Charge Adjustments. Staff agreed with the proposed eliminations of Riders 13, 14, 15, CCA and LCP. The tariff language from North Shore Rider 14, Peoples Gas Rider 15 and Rider CCA has been combined into Rider 1. Peoples Gas Rider 13 and Rider LCP are proposed to be completely eliminated. Staff Ex. 9.0 at 16-22.

c) Commission Analysis and Conclusion

We observe Staff to agree with the Utilities regarding their proposed elimination of Riders 13, 14, CCA and LCP. As such, the Commission finds the elimination of the Riders 13, 14, 15, CCA and LCP to be supported by the evidence in the record.

7. Miscellaneous Changes to Riders 1, 3, 10, and 11

a) Utilities

The Utilities point out that Staff witness Harden is in agreement with the changes to Riders 1, 3, 10 and 11, and no other parties addressed these matters.

b) Staff

Staff explains that the Companies proposed miscellaneous changes to Rider 1 – Additional Charges for State and Municipal Utility Taxes, Rider 3 – Budget Plan of Payment, Rider 10 – Controlled Attachment Plan and Rider 11 – Adjustment for Incremental Costs of Environmental Activities.

According to Staff, the changes include changing the title of the rider, adding language from proposed elimination of other riders, a change in the calendar year, converting language to a number formula and changes for consistency with other tariffs

or practices and to make the language more understandable. Staff recommends approval of the changes to Rider 1, 3, 10 and 11. Staff Ex. 9.0 at 22-32.

The Companies also proposed changes to Rider 9 to reflect the applicability of the rider based on their proposal to eliminate and rename applicable transportation riders. NS Ex. VG-1.0 3REV at 34 and PGL Ex. VG-1.0 2REV at 37. In Staff's view, the proposed changes that refer to other riders are appropriate if the Commission approves the elimination and renaming of certain transportation riders. Staff Ex. 9.0 at 31.

c) Commission Analysis and Conclusion

Staff and the Utilities agree to the proposed changes to Riders 1, 3, 10 and 11. No other party has voiced an objection. Thus, these changes, as detailed below, are authorized by the Commission.

Rider 1, Additional Charges for Taxes and Customer Charge Adjustments

Peoples Gas proposes to revise Rider 1 to clarify language and to incorporate the language from Riders 15 and CCA, which are being eliminated. Rider 15 provides for taxes on the use of compressed natural gas while Rider CCA provides for charges arising from the Energy Assistance Act of 1989 and the Renewable Energy, Energy Efficiency and Coal Resources Development Law of 1997. PGL Ex. VG-1.0 REV at 35. Staff witness Harden concurs with the Companies' modifications. Staff Ex. 9.0 at 23. Staff agrees with Peoples Gas' proposal to revise Rider 1 to clarify language and to incorporate the language from Riders 15 and CCA which are being eliminated. The Commission finds the changes to Rider 1 to be supported by the evidence in the record.

Rider 3, Budget Plan of Payment

The Companies propose to revise the language of Rider 3 to make it more consistent with the Companies' current budget plan. PGL Ex. VG-1.0 REV at 36; NS Ex. VG-1.0 3REV at 32. Staff witness Ms. Harden finds the changes acceptable. Staff Ex. No. 9.0 at 26.

Staff agrees with the Companies proposal to revise the language of Rider 3 to make it more consistent to the Companies current budget plan. The Commission finds the changes to Rider 3 to be supported by the evidence in the record.

Rider 10, Controlled Attachment Plan

The Companies propose to revise Rider 10 to reflect the applicability of the rider based on the elimination and renaming of transportation riders and to make the language more understandable. PGL Ex. VG-1.0 REV at 34, 38. Staff agrees with the proposed changes in Rider 10. Staff Ex. 9.0 at 31-32. Staff agrees with the Companies proposal to revise Rider 10 to reflect the applicability of the rider based on the elimination and renaming of transportation riders. The Commission finds the changes to Rider 10 to be supported by the evidence in the record.

Rider 11, Adjustment of Incremental Costs of Environmental Activities

The Companies made minor editorial changes and revised Rider 11, as required by the Commission's order in Docket No. 06-0540 to reflect the Companies' change to a

calendar year for its fiscal year. PGL Ex. VG-1.0 REV at 34 & 38. Staff agrees with the proposed changes in Rider 11. Staff Ex. 9.0 at 32-33. The Commission acknowledges the submitted revisions to Rider 11 based on its Order in Docket No. 06-0540.

8. Terms and Conditions of Service

a) Service Activation Charges

(1) North Shore/Peoples Gas

The Utilities propose to increase the Service Activation Charge, which recovers a portion of the costs related to initiating gas service at an individual premises. PGL Ex. VG-1.0 2REV at 29; NS Ex. VG-1.0 3REV at 25. There are two types of service activations: a "successor turn-on," and a "straight turn-on." It is explained that a successor turn-on occurs when the customer moving out calls and discontinues gas service at approximately the same time as the applicant moving in calls and requests gas service. In this instance only a meter reading is required.

A straight turn-on describes the instance where there has never been gas service at the location, or when the prior customer cancelled service and the gas was actually turned off before new service was requested. In this instance, the gas has to be turned on and the appliances relit. Id.

Both North Shore and Peoples Gas performed a study on these charges, and the results are set out in NS Ex. VG-1.9 and PGL Ex. VG-1.10. Both of these studies, the Utilities maintain, show that the cost is higher than the respective Company's proposed change in this docket. Staff Ex. 9.0 at 7-8. North Shore proposes charging $18.00 for a successor turn-on, and $28.00 for a straight turn-on including the relighting of four appliances, plus $5.00 for the fifth and each additional appliance to be activated. NS Ex. VG-1.0 3REV at 26. For its part, Peoples Gas proposes charging $12.00 for a successor turn-on, $20.00 for a straight turn-on, including the relighting of four appliances, plus $5.00 for the fifth and each additional appliance to be activated. PGL Ex. VG-1.0 2REV at 30.

(2) Commission Analysis and Conclusion

At hand is the Utilities' proposal to increase the Service Activation Charge, which recovers a portion of the cost related to initiating gas service at a premises. Both North Shore and Peoples Gas performed a study on these charges. The results are reflected in NS Ex. VG-1.9 and PGL Ex. VG-1.10. Both of these studies show the cost is higher than the respective Company's proposed change in this docket. Staff Ex. 9.0 at 7-8. The Commission finds the proposals to increase the Service Activation Charge are acceptable and supported by the evidence in this proceeding. We further find that no party or Staff takes issue with this proposal.

b) Service Connection Charges

(1) North Shore/Peoples Gas

The Utilities explain that a "Service Reconnection Charge" is a charge assessed to a customer whose gas has previously been turned off for any number of reasons, such as nonpayment of bills or the customer's own request. PGL Ex. VG-1.0 2REV 30-

31; NS Ex. VG-1.03REV at 27. According to the Utilities, each customer is granted a waiver of one reconnection charge each year, except in the situation where the customer voluntarily disconnects and then requests reconnection within twelve months, or in the situation where service is disconnected at the main. Id.

As with the Service Activation Charge, the Utilities propose to restructure the Service Reconnection Charge to include a basic charge that includes the relighting of up to four appliances, and to assess a charge for the fifth and each additional appliance. The Utilities are proposing a slight increase to the charges for all three types of reconnection: (1) basic reconnections which only require a meter turn-on; (2) reconnections which require the Company to set a meter; and (3) reconnections that involve excavating at the main. Id.

More specifically, North Shore proposes charging $50.00 for a basic reconnection; $90.00 if the meter has to be reset; and $275.00 if service has to be reconnected at the main. NS Ex. VG-1.0 3REV at 27. Peoples Gas proposes charging $50.00 for a basic reconnection; $100.00 for a reconnection when the meter has to be reset; and $275.00 when service has to be reconnected at the main. PGL Ex. VG-1.0 2REV at 31.

The Companies provided the results of a study on these charges in North Shore Gas Ex. VG-1.9 and Peoples Gas Ex. VG-1.10. Both of these studies, the Utilities assert, show the actual cost to be even higher than the charge the Companies are proposing in this docket.

(2) Commission Analysis and Conclusion

The Utilities propose to increase the Service Reconnection Charge, and they explain that this is a charge assessed to a customer whose gas has previously been turned off for any number of reasons, including nonpayment of bills or at the customer's own request. PGL Ex. VG-1.0 2REV at 30-31; NS Ex. VG-1.03REV at 27. The Commission finds the proposals to increase the Service Reconnection Charge are acceptable and supported by the evidence in this proceeding.

c) Second Pulse Data Capability

(1) North Shore/Peoples Gas

Certain meters, meter correctors, and daily demand measurement devices are capable of delivering a "second pulse" signal to specialized devices that can capture and transmit metering data. Second Pulse Data Capability can provide this signal and make real-time usage readings to customers. While the Companies do not require such capability, a few large volume customers have made requests to receive the second pulse output to help manage their gas usage. PGL Ex. VG-1.0 2REV at 33; NS Ex. VG-1.0 3REV at 29. Here, the Utilities propose a charge of $14.00, set at cost, to customers who elect Second Pulse Data Capability. Id.; Id. at 30.

The Utilities point out that Staff witness Harden reviewed North Shore's and Peoples Gas' supporting documentation and she agrees to the monthly charge for Second Pulse Data Capability. Staff Ex. 9.0 at 12. The Utilities further observe that no other parties have addressed this issue.

North Shore and Peoples Gas also propose to revise the first sentence of the second paragraph of the section entitled "Second Pulse Data Capability" to state "Initial terms of the contract shall end on the first April 30 following the effective date thereof, and the contract shall automatically renew for one-year periods upon expiration of the initial term and each one-year extension." This change does not substantially affect the second pulse proposal. The Utilities explain that the change was made for consistency since many of the contracts automatically rollover on May 1. NS-PGL Ex. VG-3.0 at 29.

(2) Commission Analysis and Conclusion

We observe the Utilities to propose a charge of $14.00, set at cost, to customers who elect Second Pulse Data Capability. PGL Ex. VG-1.0 2REV at 33; NS Ex. VG-1.0 3REV at 30. We further note that Staff witness Harden has reviewed North Shore and Peoples Gas' supporting documentation and she agrees to the monthly charge for Second Pulse Data Capability. Staff Ex. 9.0 at 12. On the entirety of the record, the Commission finds the proposals regarding Second Pulse Data Capability, including the cost-based charge, acceptable and supported by the evidence in this proceeding.

X. TRANSPORTATION ISSUES

A. Overview

This Section addresses issues concerning customers who obtain gas supply from alternative providers and purchase gas transportation from the Utilities.

B. Uncontested Issues

1. Demand Diversity Factor

a) North Shore / Peoples Gas

Under its current rates Peoples Gas' demand Diversity Factor is 0.50. PGL Ex. TZ-1.0 at 21. Peoples Gas has proposed to set its Diversity Factor to 0.87. Id. at 21-22. Neither any Intervenor nor Staff has filed any evidence in opposition to this proposal. Under its current rates North Shore's demand Diversity Factor is 0.50. Id. at 20. North Shore has proposed to set its Diversity Factor to 0.75. NS Ex. TZ-1.0 at 20. Neither any Intervenor nor Staff has filed any evidence or otherwise submitted any statement in opposition to this proposal.

b) Commission Analysis and Conclusion

The Commission finds that North Shore's proposed demand Diversity Factor of 0.75 is supported by the evidence and is approved. The Commission finds that Peoples Gas' proposed demand Diversity Factor of 0.87 is supported by the evidence and is approved.

2. Daily Demand Measurement Device Charge

a) North Shore / Peoples Gas

Peoples Gas proposed to change its Daily Demand Measurement Device Charge from a range of three charges, depending on the type of meter, to a single charge of $28.00 per month. PGL Ex. TZ-1.0 at 48; PGL Ex. TZ-1.17. Neither any Intervenor nor Staff has filed any evidence in opposition to this proposal. North Shore proposed to

change its Daily Demand Measurement Device Charge from a range of three charges, depending on the type of meter, to a single charge of $34.00 per month. NS Ex. TZ-1.0 at 46; NS Ex. TZ-1.17. Intervenors and Staff filed no evidence in opposition to this proposal.

b) Commission Analysis and Conclusion

The Commission finds that North Shore's Daily Demand Measurement Device Charge of $34.00 per month is supported by the evidence and is approved. The Commission finds that Peoples Gas' Daily Demand Measurement Device Charge of $28.00 per month is supported by the evidence and is approved.

3. Elimination of Rider TB (North Shore)

a) North Shore

North Shore proposed to eliminate Rider TB. NS Ex. TZ-1.0 at 17. Intervenors and Staff filed no evidence in opposition to this proposal.

b) Commission Analysis and Conclusion

The Commission finds that North Shore's proposed elimination of Rider TB is supported by the evidence and is approved.

4. Revised Calculation of Average Monthly Index Price

a) North Shore / Peoples Gas

North Shore proposed to change its calculation of the Average Monthly Index Price ("AMIP") from an average of weekly indices to an average of daily indices. NS TZ-1.0 at 45. Peoples Gas proposed to make the same change to its calculation of the AMIP. PGL TZ-1.0 at 46. Intervenors and Staff filed no evidence in opposition to this proposal.

b) Commission Analysis and Conclusion

The Commission finds that each Utility's proposed change to its calculation of AMIP is supported by the evidence and is approved.

5. Administrative Charges for Rider SST and Rider P

Peoples Gas proposed that the monthly administrative charge for Rider SST be reduced to $23.00 and that the monthly administrative charge for Rider P be set at $18.00. PGL Ex. TZ-1.6, p. 1 of 2. North Shore proposed that the monthly administrative charge for Rider SST be reduced to $21.00 and that the monthly administrative charge for Rider P be set at $13.00. NS Ex. TZ-1.6, p. 1 of 2.

Vanguard initially objected to each Utility's proposal to round the charges and complained that these rates should be set only to recover costs incurred. Vanguard Ex. 1.0 at 18; Vanguard Ex. 2.0 at 18.

In rebuttal Mr. Zack testified that the Utilities did not object to setting the Rider SST charge at $23.16 for Peoples Gas and $21.48 for North Shore and the Rider P charge at $17.55 for Peoples Gas and $12.61 for North Shore. NS-PGL Ex. TZ-2.0, at 45. No other party expressed any opposition to the revised administrative charges

reflected in Mr. Zack's rebuttal testimony. Furthermore, in light of the Utilities' proposals to retain a form of Rider FST, the Utilities recalculated these monthly administrative charges, and the recalculated charges would yield a Rider SST charge of $11.24 for Peoples Gas and a Rider SST charge of $8.94 for North Shore, and a Rider P charge of $8.36 for Peoples Gas and a Rider P charge of $4.95 for North Shore. NS-PGL Ex. TZ-3.0 at 6; NS-PGL Ex. TZ-3.1.

Commission Analysis and Conclusion

The Commission finds that North Shore's proposed Rider SST charge of $8.94 and its proposed Rider P of charge $4.95 are supported by the evidence and are approved. The Commission finds thatPeoples Gas's proposed Rider SST charge of $11.24 and its proposed Rider P of charge $8.36 are supported by the evidence and are approved.

6. Elimination of 120 Day Meter Read Requirement for "Choices For You" Enrollment

a) North Shore / Peoples Gas

Consistent with the requirements of Rider SVT, the Utilities' practice has been to hold any "Choices For You" ("CFY") customer enrollment request if there is not an actual reading of a customer's meter in over 120 days.

b) Other Parties

RGS proposed that this requirement be eliminated. RGS Ex. 1.0, 42.

c) North Shore / Peoples Gas Response

The Utilities have accepted RGS' position on this issue, so it is no longer contested. NS-PGL Ex. TZ-2.0 at 58.

d) Commission Analysis and Conclusion

The Commission finds that proposed elimination of the 120 day meter read requirement for CFY enrollment is uncontested and reasonable we approve it.

7. Meter Reading

This issue has been moved to Operating Expense, Uncontested Issue No. 8, Section III.B.8 above.

8. Automatic Meter Reading

a) Other Parties

Vanguard and Multiut argued that the availability of automatic meter reading ("AMR") addressed the Utilities' concerns about meter reading for Rider FST customers. Vanguard Ex. 1.0, 11-12; Vanguard Ex. 2.0, 11-12; Multiut Ex. 1.0, 6.

b) North Shore / Peoples Gas Response

The Utilities responded that AMR did not alleviate the larger issue of the need to better align customer usage with daily injection and withdrawal rights. NS-PGL Ex. TZ-2.0 at 6. However, in light of the Utilities' withdrawal of their proposal to eliminate Rider

FST and, in their proposed form of Rider FST, to retain the absence of a daily metering requirement, *infra*, Section X.C.1., this argument is moot.

c) Commission Analysis and Conclusion

The Commission finds that the issue raised by Vanguard and Multiut regarding automatic meter reading is moot in light of North Shore's and Peoples Gas' withdrawal of their proposal to eliminate Rider FST.

9. Billing Demand Determination

a) Other Parties

CNEG proposed that the Utilities be compelled to change their method of determining a customer's Billing Demand from being the customer's highest daily demand in therms from December to February of the most recent 12 month period to the arithmetic average of the customer's highest five daily demands in therms from December to February of the most recent 12 month period. CNEG Ex. 1.0 at 25.

b) North Shore / Peoples Gas Response

The Utilities originally opposed CNEG's proposal. NS-PGL Ex. TZ-2.0 at 46. However, they also indicated they could accept a compromise revision to the Billing Demand definition based on certain alternate tariff language proposed by CNEG. NS-PGL Ex. TZ-2.0 at 46. In rebuttal testimony, CNEG stated it was willing to accept the Utilities' compromise language on this issue. CNEG Ex. 2.0 at 34. Other Intervenors and Staff filed no testimony in connection with the proper determination of Billing Demand.

c) Commission Analysis and Conclusion

The Commission finds that North Shores' and Peoples Gas' proposed revised definition of Billing Demand is uncontested and reasonable, and therefore approves it.

10. Imbalance Trading

a) North Shore / Peoples Gas

In its original filing, Peoples Gas proposed to expand the circumstances under which imbalance trades would be allowed. PGL Ex. TZ-1.0 at 49. It proposed that trades be allowed for any movement of gas to or from a customer's Allowable Bank ("AB") for any reason, as long as (1) they net to zero within Peoples Gas' system; (2) they cannot reduce bank balances below minimum bank requirements or increase them above maximum bank requirements; (3) they are confirmed by both parties; (4) they are done via PEGASys^{TM}; and (5) they may not eliminate daily balance penalties. North Shore originally proposed identical permissible imbalance trading provisions. NS Ex. TZ-1.0 at 46-47. In rebuttal, Mr. Zack clarified that an additional condition of a permissible trade was that a customer could not trade gas in excess of the amount of its imbalance. NS-PGL Ex. TZ-2.0 at 65.

b) Commission Analysis and Conclusion

The Commission finds that North Shore's and Peoples Gas' proposals to expand the circumstances under which imbalance trades would be allowed are uncontested and reasonable, and the Commission approves them.

C. Large Volume Transportation Program

1. Rider FST

Each Utility originally proposed to eliminate its Rider FST (Full Standby Transportation), recommending that existing FST customers either take transportation service under Rider CFY or Rider SST (each as modified), or elect retail sales service. PGL-NS Ex. TZ-1.0. After objection from the transportation customers participating in this docket, the Utilities proposed to retain an alternative form of Rider FST. PGL-NS Ex. TZ-3.0 at 4. The revised Rider FST would cap a customer's daily nominations[49] at that customer's average daily use in the parallel month of the prior year, plus 0.67% (20% divided by 30) of the customer's allowable bank ("AB") of stored gas, with the customer adhering to the Utilities' end of season restrictions on storage balances. Id. at 5. The Utilities also modified their proposed changes to Rider SST (discussed later in this Order). Both FST and SST customers would have the identical end of season storage inventory requirements with the applicable Utility.

The Utilities aver that proposed Rider FST retains many of the existing features of current Rider FST. Proposed Rider FST also includes an updated Diversity Factor based on the study used to support the Rider SST Diversity Factor, several editorial changes for consistency with Rider SST, incorporation of the expanded imbalance trading rights and, based on the study used to support other administrative charges, revised administrative charges of $8.94 for Peoples Gas and $11.24 for North Shore.

The Utilities assert that their revised Rider FST incorporates suggestions made by Vanguard and Staff. Although the transportation intervenors express satisfaction with the Utilities' proposal to retain Rider FST, they object to various elements in the revised version of the Rider. Since these objections principally concern the Utilities' proposed injection and withdrawal limits and seasonal cycling requirements, we will address those matters in subsection X.C.4 of this Order, below.

Commission Conclusion

The Commission approves the Utilities' proposal to retain Rider FST for each Utility. We find that the proposed administrative charges of $11.24 for Peoples Gas and $8.94 for North Shore are supported by the evidence and are approved, as are the other revisions not otherwise modified or rejected elsewhere in this Order.

2. Rider SST

In response to other parties' criticisms during these proceedings, the Utilities modified their proposed changes to Rider SST (Selected Standby Transportation).

[49] A nomination is a quantitative declaration of intended gas delivery, at a pre-selected interval (e.g., intra-day, daily, weekly, monthly) or on an as-needed basis.

PGL-NS TZ-3.0 at 9-10. In lieu of their original proposals for daily injection and withdrawal limits, the Utilities' revised Riders SST would limit a customer's monthly injections to 20% of AB converted to a daily injection limit, but there would not be additional daily limits on a customer's withdrawals from AB beyond limits currently in effect. Because Rider SST consumption is metered daily, the Utilities set a daily injection limit rather than a limit based on an estimate of prior year's usage. The Utilities state that this will allow Rider SST customers to adjust for expected changes in consumption and still make AB injections. The revised Riders SST would have new daily and monthly injection provisions, in the form of nomination limits, similar to proposed Rider FST, while retaining the existing daily and monthly withdrawal provisions. Rider SST would also have the seasonal cycling requirements applicable to proposed Rider FST.

The transporters oppose the cycling requirements and injection limits in Rider SST. Again, the Commission will address those matters in subsection X.C.4 of this Order, below.

Commission Conclusion

As we did with respect to Rider FST, the Commission approves the Utilities' Riders SST for each Utility, except insofar as terms it contains are modified or rejected elsewhere in this Order.

3. Daily Metering Requirements

The Utilities contend that their revised proposals regarding Riders FST and SST essentially moot this issue. Customers currently served under Rider FST can continue to receive service under that Rider without daily metering. Customers currently served under Rider SST, and any customer electing to be served under Rider SST in the future, would be required to have their consumption metered daily. Staff finds this arrangement acceptable, since Rider FST customers will not have to incur meter costs and Rider SST customers will either have a meter already or will switch to SST knowing what is required.

Commission Conclusion

The Commission finds that there is no dispute left for decision.

4. Injection, Withdrawal and Cycling Requirements seasonal cycling requirements

The Utilities propose that large volume transportation customers satisfy biannual storage cycling requirements under either Rider FST or Rider SST. During the gas injection season, the Utilities would require customers to inject gas into the Utilities' storage facilities by November 30th of each year. The required injection would be 70% of aPeoples Gas's customer's (or 75% of North Shore customer's[50]) "allowable bank" -

[50] As originally proposed, North Shore's injection threshold was 85% of allowable bank. However, the Utilities, CNEG and Vanguard subsequently agreed that North Shore's seasonal injection target should

the customer's maximum daily quantity multiplied by a Utility-selected number of storage days (approximately 29 for Peoples Gas and 26 for North Shore). Tr. at 548-49 (Zack). If a customer falls short of the required threshold, the pertinent Utility would charge the customer on November 30th for the shortfall, at a price determined by the AMIP for the cost of gas at Chicago for November, plus 10%. NS-PGL Ex. TZ-3.02. Currently customers face no such requirement.

Similarly, during the gas withdrawal (or heating) season, the Utilities would require customers to withdraw gas from their storage facilities so that only 35 per cent of the "allowable bank" remains by March 31st. If the FST customers fail to reduce gas in storage to the 35% Peoples Gas threshold or the 24% North Shore threshold, the Utilities will "buy back" the excess at 90 per cent of the AMIP for the month of March. Tr. at 551 (Zack).

Each Utility presented six years of operating data to support its respective proposed storage cycling requirements. NS Ex. TZ-1.1; PGL Ex. TZ-1.1. The Utilities maintain that in each case the data show that the proposed storage cycling requirements are more favorable to large transportation customers than the storage cycling requirements applicable to each utility with respect to its leased storage services.

Multiut does not presently inject gas into storage, because it purchases gas for direct delivery to its customers, either on the spot market or from the Utilities under Rider FST. Multiut Ex. 1.0 at 3. Consequently, Multiut avers that the Utilities' proposed seasonal cycling requirements will cause it to alter its operations by requiring pre-winter gas purchases and spring withdrawals or pay a penalty for failing to do so. Multiut posits that it could be forced in the summer to purchase injection gas from the Utilities at 110% of market price, then sell that gas back to the Utilities at the end of March at 90% of market price. Thus, Multiut contends, the Utilities "could make a 20 per cent spread by buying and selling to the customer the same gas in storage." Multiut Init. Br. at 7. Furthermore, Multiut emphasizes, Section H of Rider FST allows the Utilities to restrict the customer's nomination of gas to be delivered each day. Multiut states that the Utilities have imposed such restriction during 42% of the days in 2004 through 2006. Multiut Ex. 1.0 at 5. Therefore, Multiuit concludes, the Utilities have the power to prevent customers from injecting or withdrawing gas to meet cycling requirements. On exceptions, Multiut requests exclusion from the Utilities' proposed mandatory seasonal cycling. Multiut BOE at 3.

CNEG argues that the Utilities have not shown that their proposed seasonal cycling targets are operationally necessary. CNEG acknowledges the periodic necessity to fill and empty aquifer storage fields, but asserts that it is unnecessary for transportation and sales customers to cycle their storage gas on the same seasonal schedule. "For many years PGL has been able to properly cycle its gas…to meet its own operational and seasonal requirements without any maximum or minimum storage

be reduced to 75% of allowable bank. *E.g.*, CNEG BOE at 3-4. This intra-party agreement was linked to other elements of a multi-issue agreement among these parties, reached after distribution of the ALJs' Proposed Order.

level requirements imposed on transportation customers." CNEG Init. Br. at 16. Moreover, Peoples Gas "has never failed to properly cycle Manlove Field in spite of no cycling requirements for transportation customers." Id. In CNEG's view, the focus of seasonal cycling should continue to be on the aggregate performance of all customers (both sales and transportation), not on individual customer performance.

Additionally, CNEG questions whether the Utilities' proposed target storage inventories for November 30 and March 31 are, in fact, "soundly supported by the underlying assets of the [U]tilities." Id. at 17-18. CNEG asserts that:

> …nearly 85% of [Peoples Gas's] total storage assets have fall injection requirements that either are non-specific or less stringent than either a 70% or [formerly] 85% target. Only service under NGPL [Natural Gas Pipeline Company] Rate Schedule DSS service has a higher fall cycling target of 95%, but compliance for that target is measured during a 30-day window from October 15 to November 15. For spring withdrawal requirements, 80% of [Peoples Gas's] total storage assets have withdrawal requirements that are less stringent than the 35% and 24% proposed. Only ANR Pipeline Company's Rate Schedule FSS service has a more stringent target of 20% or less by March 31. (PGL Ex. TZ 1.0…; CNEG Cross Ex. 2 and 3 (Zack)).

Id. at 18.

IIEC, along with CNEG, dismisses the Utilities' contention that seasonal cycling requirements for transportation customers will protect the interests of sales customers. Indeed, IIEC claims, the absence of a common cycling schedule for transportation and sales customers "could actually cost sales customers money." IIEC Init. Br. at 11. That is, even though sales customers would "save some money" if transportation customers adhered to the Utilities' proposed seasonal cycling requirements, they would "save even more money." Id. *citing* IIEC Ex. 1.0 at 23-24.

The large transportation customers also disagree with the Utilities' differing cycling requirements for Peoples Gas and North Shore. They argue that the two Utilities essentially share Manlove Field, almost of which is devoted to Peoples Gas. They do not believe that the nominal distinction between corporate affiliates justifies separate cycling requirements.

The Utilities reply that they have properly cycled their storage gas in the past without the proposed cycling requirements only because they have imposed delivery restrictions on transportation customers as needed. They reiterate that their core objective is to meet their own seasonal cycling targets without being thwarted by transportation customers who take supply actions inimical to that goal. They also insist that they should not share a common cycling target, because they are separate utilities with separate distribution systems, assets and discrete storage rights.

Commission Conclusion

Seasonal Cycling Requirements

In Nicor we approved a fall injection target but not a spring withdrawal target. The Commission concluded that the former was a valid operational requirement that would not unduly burden transportation customers, but the latter was not. Nicor, Docket No. 04-0779, Order at 146. We are not persuaded to approve a different regime in these dockets. The Utilities generally assert that "the storage and standby rights of each Utility's transportation customers need to be shaped to be consistent with each Utility's individual gas supply portfolio, and each Utility needs to have an annual mechanism to adjust those rights as its individual gas supply portfolio changes." That is not enough to outweigh the considerable difficulties the seasonal cycling requirements will present for transportation customers. *E.g.*, CNEG Init. Br. at 20-24. While we are willing to subordinate those difficulties to the Utilities' operational needs during the heating season, the balance tips in the transportation customers' favor in the spring.

We note that the Utilities attempt to elide our Nicor ruling by claiming that "[t]he reason the Commission did not impose a spring withdrawal target on Nicor Gas' transportation customers is that Nicor Gas itself did not routinely operate its system in accordance with the same spring withdrawal targets which it was trying to apply to its transportation customers." PGL-NS Rep. Br. at 150. That is misleading. The Order asserts multiple reasons for our ruling, with the greater emphasis placed on the burden the spring target imposed on transportation customers.

The Commission also observes that the Utilities strongly emphasize the cycling requirements they face with respect to leased storage facilities. Without intending to minimize in any way the significance of those requirements, we see that the larger volume of stored gas managed by Peoples Gas resides in Manlove Field, where Peoples Gas establishes its own cycling schedule. Thus, most of the Utilities' own storage flexibility is constrained by the general need to recycle Manlove, not by storage leases. That fact, in turn, allows some latitude when balancing the competing and equally legitimate needs of the Utilities and the transporters.

Accordingly, injection season requirements of 70% and 75% of AB are approved for, respectively, Peoples Gas and North Shore, while seasonal withdrawal requirements are disapproved. We decline to exempt suppliers like Multiut, who prefer not to inject third-party gas into storage, from the pre-winter injection requirement. Under the terms of Rider FST, such suppliers' operations do meaningfully rely upon and affect the Utilities' gas storage management[51] and, therefore, they will not be exempted from the requirements imposed on suppliers that do inject.

[51] "Every day that the supplier delivers more gas than the FST customer consumes, the customer uses the AB. Every day that the supplier delivers less gas than the FST customer consumes, the customer uses the AB, to the extent inventory is available…[I]t is inevitable that deliveries and consumption do not match each day, and the AB and standby gas purchases are how this difference is accommodated." PGL-NS Ex. TZ-2.0 at 10. Thus, even without injection, FST customers utilize storage assets under the tariff, for excess delivery or as a source of standby gas supply.

The Commission will not require a common seasonal target for the two Utilities. They correctly demonstrate that they are separate entities with distinct profiles and tariffs.

Daily Injection Limits

As already explained, the Utilities would cap a customer's Maximum Daily Nominations ("MDNs") throughout the year at that customer's average daily use in the parallel month of the prior year, plus 0.67% (20% divided by 30) of the customer's AB. Any daily imbalance between the allowable daily nomination and actual usage would be subject to substantial imbalance account charges (10 cents per therm on a Non-Critical Day and six dollars per therm on a Supply Surplus Day).

The Utilities generally support their proposals with the proposition that they are required, due to their responsibility for the reliable functioning of their systems, to reasonably limit the prerogatives of the various customer classes, including large volume transporters.

For Rider FST, Vanguard would agree to be limited to the proposed MDNs during the months of April through October of each year. However, for the rest of the year (November-March) Vanguard recommends that a supplier's Maximum Daily Quantity ("MDQ")[52] continue to determine its maximum daily nomination. According to Vanguard, Nicor now manages its storage assets in a similar fashion, as a result of our ruling in Nicor's most recent rate case that "[t]o the extent possible, the Commission would prefer to increase rather than reduce the flexibility of customers." Vanguard Init. Br. at 3 (quoting Nicor, at 131). Vanguard proposes the same MDN limits for Rider SST.

CNEG claims that the proposed daily nomination limits "significantly diminish the value of Rider SST for transportation customers." CNEG Init. Br. at 12. Current Rider SST allows a customer to have as much as its entire MDQ delivered, and the customer can inject any excess above usage into the AB (subject to AB limits). In contrast, under revised Rider SST, if the customer's present actual usage is greater than 0.67% of its AB, then a withdrawal from storage may need to occur, rather than the injection that would have been permitted under current Rider SST. This limits the customer's ability to inject gas. "Normal imbalances on any given day may actually be larger than the allowed storage injection for the day." Id. (*citing* Tr. 787 (Rozumialski).

Moreover, CNEG charges, revised Rider SST also adversely impacts a customer when usage is below expectation. Delivered gas above 0.67% of the AB plus actual usage would be subject to an imbalance charge of $.10 per therm. The prohibition on intraday nominations to adjust for normal production and weather changes "exacerbates the problems of the proposed daily injection limits." Id.

[52] Maximum Daily Quantity is defined in the Utilities' proposed SST tariffs as the maximum amount of customer-owned gas that a customer may deliver on any day. PGL-NS Ex. TZ-3.3

Thus, CNEG initially recommended that daily injections either be limited to MDN as defined in Rider FST (but applicable year-round and not merely the April-October period as proposed by Vanguard), or remain identical to current tariffs by limiting daily injections year-round to MDQ. However, after distribution of the ALJ's Proposed Order, CNEG, Vanguard and the Utilities reached agreement (for purposes of this administrative litigation) that an MDN limit would apply under both Riders FST and SST during April through October - with MDN defined as the maximum amount of gas a customer may deliver on any day. MDN would be calculated as previously described (average daily use in the parallel month of the previous year plus .67% of the customer's AB). CNEG, Vanguard and the Utilities additionally agreed that if a large transport customer's "usage profile materially changes" from the previous year, the Utilities "would accept [the] customer['s] request[] to revise MDN and in good faith entertain agreement to a revised MDN based upon demonstrable evidence of" such material change. CNEG BOE at 4.

The IIEC and Multiut did not enter into the agreement described in the preceding paragraph. IIEC maintains that the agreement should not be adopted by the Commission for determining FST and SST customers' daily injection limits. IIEC argues that the limits are not aligned with the fluctuating business needs of IIEC end-users, and that the potential for modifying MDN suggested in the agreement will not cure that defect. IIEC RBOE at 5-6. IIEC also charges that daily nomination limits would impair customers' ability to meet injection season cycling targets. Staff's view is that the MDN provision in the agreement is appropriate for Rider FST because FST customers do not have demand meters, but not for Rider SST. Staff RBOE at 60.

The Commission readily acknowledges the serious and complex responsibilities the Utilities bear with respect to management of their storage assets. We also recognize the desire of large commercial gas end-users to manage gas supply in a manner that efficiently contributes to their enterprises. We are also committed to encouraging competitive gas supply, so that customers enjoy the benefits competition can provide. Our task is to optimally balance these interests. The above-described agreement on daily nominations is satisfactory to the Utilities and two of the three suppliers that chose to participate in these ratemaking proceedings, but the end-users represented by IIEC oppose it.

Although the IIEC arguments are largely theoretical and not supported by evidence of impairment for any particular customer, the Commission does not doubt their general validity. While IIEC end-users will not lack the gas supply their businesses need, they may have less storage control than they want. Nonetheless, while we certainly intend to promote profitable economic activity, that is an indirect objective. Our direct mandate is utility regulation. The Utilities here insist that effective and reliable storage system management requires daily nomination limits after the end of the heating season. Maximum daily injection capability diminishes from the start of the injection season until its conclusion because field pressure accumulates. PGL-NS Ex. 1.0 at 12-13. To preserve customer flexibility, we rejected the Utilities' proposed March 31 withdrawal target. As a result, the Utilities may begin the injection season already

having more gas in storage than they would prefer. IIEC itself states that "if transportation customers bring in more gas in a month when the [Utilities] are also trying to fill up their fields, there could be a problem. Those would be the months May through October." IIEC Ex. 1 at 19. Ultimately, averting such problems is in the interest of IIEC end-users.

Accordingly, with regard to daily nominations specifically, the Commission will approve the terms agreed to by CNEG, Vanguard and the Utilities, quoted above, which appear reasonable[53] and achieve a balance of interests acceptable to those parties. Outside of the April-October period, the MDQ nomination benchmark will continue to apply, as it does under the Utilities' currently-filed rates.

As indicated in earlier subsections of this Order, Riders FST and SST are approved subject to our rulings in this subsection.

5. Unbundled Storage Bank ("USB")

Collectively, the IIEC, Vanguard and CNEG propose that the Utilities offer an unbundled storage service ("USB") to transportation customers[54]. These proponents stress that the Utilities have access to Manlove Field and are, therefore, capable of offering USB as an unbundled storage service. IIEC Init. Br. at 14. In fact, the Proponents note, the Utilities have already offered USB to third parties such as Merrill Lynch, and to smaller customers served under SC 2.[4] Moreover, North Shore receives its storage service from Peoples Gas at Manlove. In contrast, the Proponents emphasize, transportation customers cannot presently obtain USB from the Utilities without also acquiring the Utilities' standby service. Id. at 12-13. Furthermore, according to the Proponents, "because transportation customers can now only secure storage service if they purchase standby service…these customers will be exposed to proposed [standby rate] increases of 74% on [Peoples Gas] and 50% on [North Shore]." Id. at 13.

The Proponents' contend that their suggested formula for allocating storage to transportation customers at Manlove is "similar to a formula used by the Commission to allocate Nicor's underground storage for unbundled access" in Nicor. Id. at 14. Under the Proponents' formula (after adjustments reflecting "the diversity of transportation customers use of storage"), Peoples Gas transportation customers would receive 20 days of storage and North Shore transportation customers would receive 6 days. Id. at 15. Thus, 13.1 BCF of storage would be available to transportation customers, equaling about 37.7% of Manlove's storage capacity. Id. Transportation customers represent about 40% of the Companies' annual thru-put. Id.

[53] The agreement contemplates MDN revision in the event of material change in customer usage profile. The Commission approves this with a firm prohibition against discrimination by a Utility toward any customer or supplier (within the meaning of 220 ILCS 5/9-241), and with an unambiguous expectation that agreement to requested revision will not be unreasonably withheld.

[54] For the purposes of this subsection of the Order only, the three parties will be denominated collectively as the "Proponents."

[4] Customers must pay for Manlove storage as part of the SC 2 Rate. IIEC/CNEG/VES Ex. 1 at 6.

The Proponents also offer a formula for establishing a common USB rate for the Utilities' transportation customers. Proponents characterize the formula as "patterned after the rate format" we approved in Nicor. Id. at 16. The formula uses Manlove's total cost of service total capacity, excluding the carrying costs of top gas (because transportation customers provide their own and have no right to the Utilities' top gas without paying an additional charge). Id. Proponents' formula yields a storage charge of 0.66 cents per therm per month, which Proponents adjust down to 0.60 cents to account for the diverse storage usage characteristics among transportation customers." Id. at 17.

The Utilities assert that the proposed USB would provide USB customers "with daily injection and withdrawal rights vastly exceeding the capabilities of Manlove," thereby causing the Utilities' sales customers "to subsidize the USB service." PGL-NS Init. Br. at 196-97. The Utilities further argue that the USB proposal would "make it more difficult for the Utilities to manage their systems for the benefit of all their customers." Id. at 197. The Utilities also believe it is significant that they are each separate entities with "different gas storage rights," and that North Shore has no storage asset to unbundle because it does not own Manlove or any other storage field. Id.

Staff also opposes the USB proposal, because it involves only Manlove Field, which Staff views at the Utilities' lowest cost storage asset. Staff Ex. 24.0 at 13. Staff avers that the storage available to transport customers should equitably reflect the cost and availability of *all* storage resources that the Utilities own or lease, so that other customer groups do not have to pay "rates that reflect higher cost [storage] resources. Id. at 13.

Commission Conclusion

The Commission will not approve the USB proposal. We agree that the proposal is tied to the Utilities' lowest cost storage asset and would benefit large transportation customers disproportionately, to the detriment of sales customers. Additionally, we cannot find that record evidence disproves the Utilities' assertion that the USB proposal will interfere with their ability to manage their storage assets for the benefit of all customers. The proponents of USB request reservation of a substantial portion of Manlove Field in proceedings in which the Utilities are asserting the need for greater control of its storage assets[55]. Without more, the Commission declines to disregard the Utilities' insistence that the USB proposal will unduly burden their storage operations.

[55] The Commission notes that, on exceptions, the IIEC asserts that Peoples Gas offered unbundled storage to Merrill Lynch (and, in part for that reason, should be ordered to implement USB here). IIEC BOE at 6 & 7. Peoples Gas responds, as it did with prefiled evidence, that the Merrill Lynch arrangement involved a capacity release of storage rights PGL obtained from others (and which transportation customers could have, but did not, bid for). PGL-NS RBOE at 5 (*citing* PGL-NS Ex. TZ 2.0 at 16-17). Thus, the Merrill Lynch transaction does not demonstrate that the Utilities can readily offer a tariffed storage service (particularly a service tied to Manlove Field) to transportation customers generally.

6. Rider P-Pooling

a) Pool size limits

The Utilities each proposed to increase the maximum pool size under Rider P from 150 to 200 accounts. NS Ex. TZ-1.0 at 43; PGL Ex. TZ-1.0 at 45. In response, Vanguard proposed that the pool size limit be increased further, to 300 accounts. Vanguard Ex. 1.0 at 5-6; Vanguard Ex. 2.0 at 5-6[56]. CNEG proposed that the pool size limit be eliminated entirely. CNEG-Gas Ex. 1.0 at 18. Staff also believes that the pool size limit should be eliminated entirely. Staff Ex. 24.0 at 21.

The Utilities contend that their recommended limit is dictated by "administrative and billing system reasons." PGL Ex. TZ-2.0 at 35. "[S]ystem features require that all sub-accounts [in a pool] be billed before the pool bills. If one sub-account cannot be billed as a result of a billing exception, the pool cannot bill. Allowing more accounts…will increase the time needed to review and resolve billing exceptions and bill a supplier pool." Id.

CNEG argues that the key consideration is whether removing the pooling cap would increase costs, and further avers that the Utilities have not proven such cost increase. CNEG Init. Br. at 28. Indeed, CNEG claims that expanded pool sizing would save administrative costs for the Utilities. Id. at 29. CNEG also identifies several utilities that do not cap the number of accounts in a customer pool. Id. at 28.

Commission Conclusion

None of the Utilities' opponents on this issue successfully refute the Utilities' assertion that expanded pool membership increases the likelihood of delay-causing, account-specific billing issues *within the enlarged pool*. To the contrary, Vanguard accepts this proposition. Vanguard Ex. 3 at 5. On the other hand, the Utilities do not demonstrate why the potential delay associated with 200 accounts is acceptable, while the delay associated with a larger number is not. The Utilities are presumably attempting to strike a balance between reasonably prompt billing (which is likely to make receipt of revenues correspondingly prompt) and the advantages all stakeholders derive from pooling. The Commission agrees that a balance should be achieved and, accordingly, we reject the suggestion to remove the cap altogether.

However, without evidence compelling us to strike the balance at 200 accounts, the Commission will place the balance higher - at the 300 accounts recommended by Vanguard. It is implicit in the Utilities' own proposal that they can comfortably handle larger pools than they have previously, and we agree with Staff witness Reardon that "pools provide economies to marketers that can result in lower prices for their customers." Staff Ex. 24.0 at 20. Accordingly, to promote the latter outcome, the Commission selects a pool limit that, based on the record before us, will not unduly burden any stakeholder.

[56] Ironically, in Nicor Gas Company's most recent rate case, Vanguard argued that Nicor Gas should increase its pool size limit from 50 accounts to 150 accounts, using the existence of PGL's Gas' Rider P pool size limit of 150 accounts as support for its argument. Nicor, Docket No. 04-0779, Order, at 174.

b) "Super-pooling"

CNEG and Vanguard recommend approval of super-pooling, which allows aggregation of all of a supplier's customer pools into a single pool for certain purposes, such as measuring compliance with the Utilities' inventory and daily balance requirements. These intervenors also request that their individual, or "stand-alone," accounts be included in a super-pool.

After initially opposing super-pooling, the Utilities agreed to accept super-pooling if it were used solely for the purpose of determining whether a supplier meets biannual cycling requirements and if stand-alone (non-pooled) customers were excluded. NS-PGL Ex. TZ-3.0 at 14. Vanguard would accept the Utilities' revised position, though it would prefer to include stand-alone accounts in super-pools. Vanguard Ex. 3 at 4. CNEG continues to urge that stand-alone accounts be added to super-pools and that super-pooling apply to critical and supply surplus days. Staff expresses "concerns" about super-pooling, but, "does not oppose it" insofar as it is acceptable to the utilities. Staff Init. Br. at 258.

Commission Conclusion

The Commission approved super-pooling in Nicor, to "mitigate the adverse impact of cycling requirements adopted" in that case. Nicor, Docket No. 04-0779, at 149. We see no reason to chart a different course in the present case, particularly when the Utilities are willing to accept super-pooling associated with their annual cycling requirements.

The Commission also concludes that stand-alone accounts can be included in a gas marketer's super-pool. Given the Utilities' assertion that the underlying intention of their cycling regime is to achieve *system-wide* objectives (and not to impose penalties on individual accounts), fragmentation of a marketer's stand-alone accounts is, at the least, unnecessary. The problem posed for the Utilities by inclusion of stand-alone accounts in super-pools is really a billing system problem. To alleviate that concern, we adopt CNEG's recommendation that a marketer or supplier cannot include in its super-pool any stand-alone customer that has purchased gas supply from another source during any month in which the marketer's or supplier's cycling compliance is assessed.

With inclusion of stand-alone customers, we cannot agree with CNEG that super-pooling should be utilized for assessing compliance with applicable limitations on critical days or supply surplus days. CNEG's rationale - that critical days and supply surplus days are essentially like annual cycling compliance milestones, because they "are not regular, ongoing circumstances" CNEG Init. Br. at 31 - is both incorrect and inimical to CNEG's own cause. By its terms, annual cycling compliance will be quite regular and, per our ruling here, will occur only once each year. Accordingly, for purposes of calculating annual cycling compliance, the Utilities can predictably employ an "ad hoc process that will run tangentially to their existing processing and, therefore will not require [structural modifications to billing systems]." PGL Ex. TZ-3.0 at 16. In contrast, critical and supply surplus days are temporally and quantitatively erratic. To apply super-pooling to such unpredictable events, when the appropriate treatment of stand-

alone accounts will have to be determined each time, would present the billing system complexity the Utilities reasonably want to avoid[57]. Id. at 14. Moreover, it would likely and excessively entangle the utilities in the relationship between suppliers and individual customers with respect to allocation of daily gas deliveries. Id. at 17.

CNEG proposes a mechanism for apportioning responsibility among super-pool members when the marketer or supplier is out of compliance with inventory requirements. CNEG Ex. 2.0 at 8-9. The proposed apportionment would be based upon the percentage by which an individual pool contributed to the total non-compliance margin. Id. The Utilities state that CNEG's proposal is acceptable. Zack Ex. 3.0 at 16. The Commission concurs.

c) Permitting Customers With Different Selected Standby Percentages ("SSP") to Be in the Same Pool

CNEG proposes that customers with different SSPs be allowed into the same supplier pool. CNEG Ex. 1.0 at 15. The Utilities would accept that proposal if it is implemented as follows: 1) a pool's MDQ would be the summation of the underlying customer (contract) MDQs, and 2) a pool's SSP would be the weighted average of its customers' (contract) SSPs. NS-PGL Ex. TZ 2.0 at 40. The Utilities provide a detailed example of how these guidelines would be applied. Id. at 40. CNEG states that the Utilities' implementation scheme is reasonable. CNEG Ex. 2.0 at 29. No party opposes either CNEG's proposal to include differing SSPs in common pools or the Utilities' proposed implementation of that proposal. Id. Therefore, CNEG's proposal and the Utilities' recommended implementation rules are approved.

7. Operational Issues

a) Intra Day Allocations and Intra Day Nominations

CNEG requests that we require the Utilities to accept intraday nominations for gas delivery. CNEG asserts that intraday nominations are standard practice, to varying degrees, throughout the North American natural gas industry. They say intraday nominations facilitate adjustments for unexpected events such as weather or production changes, or pipeline or utility service disruptions. Peoples Gas itself is allowed to make intraday adjustments, and allows intraday nominations on a select basis. Accordingly, CNEG insists, Peoples Gas should be required to universally permit intraday nominations for all transportation customers who represent over 40% of annual throughput, particularly given Peoples Gas' proposed storage restrictions. CNEG also underscore that the rates paid by transportation customers include the cost of leased storage services, which enable Peoples Gas to make intraday nominations.

The Utilities propose that a customer or supplier with more than one contract or pool be permitted, on an intra-day basis, to re-allocate deliveries between or among its

[57] On exceptions, CNEG argues that the Utilities could simply use the same process on critical and supply surplus days that they employ for injection season compliance. CNEG BOE at 7. That is correct, but misses the point. Since stand-alone accounts cannot be included whenever they use another supply source, the Utilities will have to determine their status for each critical or surplus day.

contracts or pools. They maintain that this will enable suppliers to reallocate gas among their contracts, to offset potential gas deficiencies and avoid penalties.

However, the Utilities are not willing to accept amended gas nominations during the course of a day. They stress that they manage an entire utility system (including supplier of last resort obligations) and must match demand with supply, despite a dynamic demand profile, on a real time basis. They say an obligation to accept intraday nominations from transporters could cause them to scramble to match supply with consumption, and then have to adjust their own supply to do so. They do not want to have to shed supply during a warm winter day while marketers are trying to increase their own supply because prices are low. They add that while intra-day nominations are industry standard for interstate pipelines, they certainly are not standard for local gas distribution companies.

The Utilities suggest caution about CNEG's comparisons with the tariffs of utilities that purportedly allow intraday nominations. They point out that the actual tariff of one of those utilities revealed that suppliers must exactly match deliveries and consumption on a daily basis, making intraday nominations more appropriate.

Commission Conclusion

The Commission finds that the Utilities' proposals to allow intraday allocations are reasonable and will provide benefits to the Utilities' transportation customers without detriment to the Utilities or their sales customers. Therefore the Commission approves the Utilities' proposals to allow intraday allocations.

The Commission also finds that CNEG's proposal to permit intraday nominations by large volume gas transporters could make it substantially more difficult to balance the Utilities' systems on a real time basis, to the potential harm of sales and other transportation customers. The Commission believes that the Utilities' nomination procedures, along with the related modifications and intra-pool allocations mandated by this Order, provide sufficient flexibility for the transporters. Therefore, we will not compel the Utilities to accept intraday nominations from large volume gas transporters.

b) Delivery Restrictions

Currently, during a delivery restriction, the subsequent day's delivery is limited to the prior day volume delivered. In CNEG's view, this is contrary to the utility's needs. Even though it would benefit the utility for a supplier to reduce deliveries, and perhaps sell some gas, the supplier will remain at the higher delivery volume and inject the unused gas into storage, additionally stressing the system. CNEG explains that the supplier must do this because, if it reduces its delivery to what it expects may actually be consumed, it is then prevented from later increasing deliveries back to more normal volumes (i.e. original baseload volume purchased for the entire month) until the delivery restriction is lifted. By reducing delivery volumes, a supplier risks being unable to deliver the gas volume necessary during subsequent days of the delivery restriction if usage returns to more normal levels. Moreover, the supplier will be forced to continue to sell gas each day during the restriction, even if it no longer wants to. This paradox occurs, CNEG concludes, because delivery restrictions do not correlate to usage, but

rather are tied to prior day deliveries which can range from a fraction of actual usage to multiples of daily usage.

CNEG proposes alternatives. It suggests that instead of using prior day deliveries for limiting subsequent day deliveries, the criteria should be usage-based (such as average daily use for the month, or the same month in the prior year, or customer MDQ) plus a storage component. Or Peoples Gas could formalize a procedure for negotiating with Peoples Gas on a case-by-case basis to impose a limited-time reduction in delivered volume with a guarantee that subsequent deliveries could return to the required delivered baseload volume, even while a restriction remains. CNEG notes that Peoples Gas already works out such arrangements, but without a governing tariff provision.

The Utilities reply that they impose delivery restrictions only when customer deliveries are disproportionate to customer consumption requirements. The Utilities recognize that the restrictions can be problematic for transportation customers, but emphasize the daily need to balance their systems, which makes delivery restrictions necessary at times. The Utilities assert that informal case-by-case negotiations are sufficient to enable a supplier to return to required baseload volume after a reduction, even while a delivery restriction continues.

Commission Conclusion

The Commission does not question that that there are times when the Utilities must impose delivery restrictions to balance their systems. We do not perceive CNEG to question that need either. Rather, CNEG seeks a solution for a collateral adverse consequence of imposing necessary restrictions. In turn, the Utilities do not question that the adverse consequence occurs. Indeed, they acknowledge working informally with transporters to alleviate the problem rationally. Accordingly, the real issue is whether to formalize the process for permitting transportation customers to return to baseload volume after a reduction, prior to termination of the delivery restriction. The Commission prefers a formal recognition of the process, to preclude discrimination and eliminate ambiguity for all stakeholders. Therefore, we direct the Utilities to create a tariff provision explicitly authorizing what has thus far been informal. The Utilities can accomplish this unilaterally, acting in good faith, and need not consult with customers regarding the text.

8. Other Large Volume Transportation Issues

a) Accounting for Trading and Storage Activity

Vanguard requests that the Utilities be directed to reinstate certain accounting practices the Utilities used before the year 2000. Vanguard asserts that the Utilities are failing to properly account for imbalance trades, new accounts added to pools and re-billed customers.

The Utilities respond that no other customer or supplier has presented the same criticisms and that no one, including Vanguard, has claimed harm as a result of the Utilities' accounting. The Utilities assert that the subject accounting practices are appropriate in light of practical administrative issues. NS-PGL Ex. TZ-2.0.

Commission Conclusion

The Commission will not resolve this dispute by ordering the Utilities to revise their accounting practices concerning imbalance traded gas and storage transfer gas. Vanguard's frustration is evident, but the absence of wider interest in this issue by other alternative suppliers does cause us to withhold action. The accounting practices Vanguard would resurrect were jettisoned approximately eight years ago, and we would expect greater industry concern if customers were actually harmed during that interval. Furthermore, the Utilities' purported accounting deficiencies are not described with sufficient granularity to justify prohibiting them.

b) Excess Bank and Critical Surplus Day Unauthorized Overrun Charges

The Utilities seek continued authority to levy an Excess Bank Charge of $0.10 per therm and a Critical Surplus Day Unauthorized Overrun Charge of $6.00 per therm. They state that the Excess Bank Charge is to deter customers from delivering gas in quantities above the customer's total AB capacity. They argue that, without the charge, a customer could have inventory substantially above AB without incurring any financial penalty. Similarly, the Utilities say, the Critical Surplus Day Unauthorized Overrun Charge is to keep transportation customer supply equal to consumption on days when critical excess of supply is coming into the Utilities' systems.

It is not clear that any party opposes these overrun charges *per se*. Although they are frequently mentioned by other parties, such discussion generally occurs in the context of quantifying the potential penalty for contravening one of the limitations proposed by the Utilities.

Commission Conclusion

The Commission finds that the Utilities' existing Excess Bank Charge of $0.10 per therm and Critical Surplus Day Unauthorized Overrun Charge of $6.00 per therm are reasonable incentives for transporters to avoid gas deliveries in excess of total AB and to keep supply equal to consumption on days when a critical excess of supply is entering the Utilities' systems. Therefore, the Commission authorizes the Utilities to continue charging their existing Excess Bank Charge Critical Surplus Day Unauthorized Overrun Charge.

c) Cash-outs Index

The Utilities seek authority to compel a customer to buy gas from the Utilities at 110% of the AMIP, and to sell gas to the Utilities at 90% of AMIP, when such customer fails to comply with the Utilities' end-of season-storage inventory requirements. They characterize these provisions as reasonable incentives to compliance. They note that the costs and revenues of these purchases and sales are accounted for in Rider 2, Gas Charge, so there is no financial benefit to the Utilities from this pricing structure.

Multiut considers these purchase and sale provisions as penalties. Multiut does not currently inject gas into storage, and it contends that the AMIP provisions will cause it to purchase gas in the summer. Nevertheless, we have approved the Utilities'

injection season cycling requirement as a reasonable storage management mechanism, so we will also approve the AMIP provision that promotes compliance with that mechanism. We note that the potential purchase and sale of the same gas that Multiut predicted cannot occur, given our disapproval of the withdrawal season cycling requirement.

Commission Conclusion

The AMIP provision is approved for the injection season and rejected for the withdrawal season.

d) Receipt of Service Classification, Rider, AB, MDQ, and SSP Information

CNEG requests that certain customer information (Receipt of Service Classification, Rider AB, MDQ, and SSP Information) be made available via PEGASys™, the Utilities' electronic bulletin board system, once the supplier obtains customer authorization, even if that occurs prior to customer enrollment by the supplier. Vanguard makes the same request, emphasizing that the pertinent information is "not sensitive data related to customer payment history." Vanguard Init. Br. at 9. Vanguard also underscores that a supplier requesting the information is obliged to sign the Utilities' "Customer Usage Data Contract" demonstrating its agreement to obtain customer approval.

The Utilities are willing to make these data available on PEGASys™ at the time of customer enrollment or if the supplier signs the "Customer Usage Data Contract," but with the proviso that the data are made available only in connection with the Utilities' large volume transportation programs. PGL-NS Ex. TZ-3.0.

Commission Conclusion

The Commission is not entirely certain about what disputes remain with regard to access to the subject customer information. The parties' briefs indicate they have moved toward agreement. Nonetheless, to provide clarity to the stakeholders, we will require that the Utilities make available Service Classification, Rider, AB, MDQ and SSP customer information, via PEGASys™, to any large volume transportation supplier that has received the customer's prior approval to obtain consumption history. The supplier need not have already enrolled the customer – the key is prior customer consent. The Commission thus approves Vanguard's proposal on this issue, although we limit our approval to the data of large volume customers, who do not have the same privacy concerns as residential and other small-volume customers.

D. Small Volume Transportation Program (Choices for YouSM or "CFY")

The RGS are alternative retail gas suppliers to customers of varying size and gas consumption. Their focus in these proceedings is the Utilities' Choices For You ("CFY") program, by which the RGS supply gas service to residential and small commercial customers. The RGS purchase gas for those customers and the Utilities receive and

deliver it via their distribution system. This process is governed by two riders in the Utilities' tariffs - Rider SVT, Small volume Transportation Service, and Rider AGG, Aggregation Service. CFY suppliers currently pay an Aggregator Balancing Gas Charge ("ABGC"), associated with Rider SVT, which is designed to recover the cost of off-system gas storage and balancing services. There is also an on-system (i.e., Manlove Field) storage component in the base rates CFY suppliers pay.

1. Storage Rights and Aggregation Rights

a) Specific Allocation of Storage Rights and Costs to CFY Customers and Suppliers (Including the RGS' proposed Rider AGG)

The RGS maintain that the Utilities recover costs through the ABGC that are "excessive relative to the storage rights that CFY suppliers receive [and that, consequently] CFY suppliers and their customers are essentially subsidizing sales service customers." RGS Init. Br. at 7. "The [Utilities'] method for allocating storage rights fails to deliver the appropriate amount of monthly and daily withdrawal and injection rights and seasonal hedging associated with the storage assets that are allocated to CFY." Id. at 8. The RGS want greater storage rights or, as a secondary alternative, recallable transfer of the Utilities' off-system storage and transportation rights[58] (and, as a tertiary alternative, reduction or elimination of the ABGC).

Accordingly, in their proposed rider AGG (RGS Ex. 2.1), the RGS first propose daily withdrawal and injection parameters for the winter and summer periods, ostensibly to equalize the daily and monthly storage rights of bundled sales and CFY customers. By RGS' calculations, CFY suppliers' annual allocation of storage capacity would be 30.985% and 39% of their customers' annual usage on, respectively, the North Shore and Peoples Gas systems. CFY suppliers' daily withdrawal rights during the withdrawal period (November through March) would be 54.79% and 65.93% of their customers' peak day demand on, respectively, North Shore's and Peoples Gas's systems. During the injection period (April through October), CFY suppliers' daily withdrawal rights would be 19.7% of their customers' peak day demand on both North Shore's and Peoples Gas's systems. Id. at 10-11.

The RGS maintain that their proposed storage allocation method is "consistent with the allocation of storage capacity to competitive suppliers in Nicor's Rider 16, Supplier Aggregation Service, which defines the delivery parameters for suppliers serving small volume transportation customers in Nicor's service territory."[59] Id. at 11. The RGS recommend that the Utilities use their proposal "as a starting point to develop a storage and delivery program for CFY suppliers and customers that mirrors Nicor's Rider 16." Id. The RGS also propose to revise the Utilities' Rider AGG to include monthly storage targets, which would replace the current month-end delivery tolerance

[58] The RGS propose other alternatives as well, each intended to increase the storage rights (or decrease the storage costs) of CFY suppliers. We address those alternatives where appropriate in other subsections within Section X.D. of this Order.

[59] The RGS state that their proposal and Nicor's storage allocation differ only insofar as the Utilities have both their own (Manlove) and leased storage. RGS Init. Br. at 9.

in that rider. The RGS's "Nicor-like" storage program would not involve contractual release of on-system or off-system assets to RGS suppliers or their customers, who would continue to pay for storage through base rates and the ABGC. Id. Although the Utilities note that the RGS's proposed storage targets for the winter months "provide substantially wider ranges than those in the Nicor Gas rider," PGL-NS Init. Br. at 208, the RGS reply that the storage assets "that CFY suppliers and customers pay for support wider storage targets than those in Nicor's Rider 16." RGS Init. Br. at 15.

The Utilities counter that they, not CFY customers, have to forecast, receive, deliver, store and balance gas supply every day. Therefore, they assert, their storage and delivery allocations for CFY customers reflect their overall objective of aligning the storage and delivery rights they own or procure with the correlative rights they provide others. More specifically, the Utilities argue, first, that the gas consumption of CFY customers is not metered daily, so there is no way to verify that CFY supplier injections and withdrawals are within the RGS' daily parameters. PGL-NS Init. Br. at 206. Second, the Utilities point out, the RGS' proposal uses peak day maximum capabilities, even though the Utilities' maximum injection and withdrawal capabilities diminish over the course of injection and withdrawal seasons. Id. Third, RGS's proposal was based on data from 2006, a single, unusually warm year. Id. Fourth, while the RGS proposal refers to monthly injection and withdrawal rights, the proposal itself does not quantify those monthly rights. Id.

With respect to RGS' selection of data from an atypically warm year, the RGS generally declare that they "would be willing to accept an allocation of storage rights using data from additional years." RGS Ex. 2.0 at 6. However, they offered no specifics, so the record does not contain RGS calculations using what RGS believes to be more typical weather data. Thus, the Commission has no basis for assessing the reasonableness of the result of altering the weather-related data in the RGS' proposal. The RGS also assert that, contrary to the Utilities' claim, the revised RGS proposal, in RGS Ex. 2.1 quantifies monthly injection and withdrawal rights. RGS BOE at 11. The RGS are correct.

Ultimately, the parties' arguments frame this question – can the additional storage flexibility sought by the RGS be accommodated by the Utilities' storage assets, along with the Utilities' obligations to their entire customer base? Regarding the magnitude of their storage assets, the Utilities underscore the diminution of their "storage and injection and withdrawal capabilities as the applicable injection or withdrawal season runs its course." PGL-NS Rep. Br. at 160. With respect to their overall obligations, the Utilities maintain that they, "rather than the CFY supplier, are responsible for handling CFY customer consumption changes as a result of weather changes and forecasting error under the CFY program." Id. The RGS rejoin that the CFY supplier has ultimate responsibility for serving CFY customers[60]. RGS BOE at 17.

[60] The respective responsibilities of the Utilities and CFY suppliers are not actually unclear. CFY suppliers bear responsibility for supplying their customers' fuel demand. The Utilities forecast likely CFY customer demand in order to manage daily deliveries. CFY suppliers have to supply the forecasted fuel

In effect, the parties perceive gas storage as a zero-sum game, in which the modicum of control (or "flexibility") at issue here will either remain with the Utilities or be transferred to the CFY supplier.

Additionally, the RGS charge that the Utilities offer large volume transportation tariffs that furnish "far greater flexibility" than is contemplated under the RGS proposal. RGS Init. Br. at 15. On exceptions, they enumerate several attributes of Rider FST that the RGS believe accord substantially greater storage and delivery rights to large volume customers than the rights given CFY customers under Rider AGG. RGS BOE at 10, 12. The Utilities reply that the two riders are simply "very different services." PGL-NS RBOE at 89. Staff shares this view. Staff RBOE at 62.

Commission Conclusion

Like the RGS, large volume customers are also demanding more storage flexibility in these proceedings (*e.g.*, through an unbundled storage service), while the Utilities themselves are seeking greater control of their storage assets. Although none of these efforts are inappropriate, simply reflecting commercial enterprises pursuing their interests, the Utilities storage resources are, in fact, finite, and the Utilities do have the responsibility of providing enough storage and delivery for every stakeholder, even under harsh weather conditions. As the RGS recognize, under their proposed rider, the Utilities "would remain the contract entity for off-system storage and maintain physical operation of on-system assets." RGS Init. Br. at 11.

The Commission is unwilling to approve RGS' proposed Rider AGG. The RGS' responses to the Utilities' system management concerns are insufficient to justify transferring more storage flexibility to CFY suppliers and customers in the manner proposed. The RGS miss the point when they assert that the Utilities' "estimate of daily customer consumption is a substitute for daily metering." Id. at 13. The Utilities are concerned about the inability to verify, without daily metering, the *actual usage* of CFY customers, not their *estimated* usage. Nonetheless, RGS emphasizes, the Utilities' sales customers also lack daily metering. But the Utilities do the forecasting and balancing for both CFY and sales customers (and purchase gas for sales customers accordingly). Thus, the Utilities effectively control the deliveries for CFY and sales customers alike, and are not granting sales customers more delivery flexibility than CFY customers[61].

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demand for delivery (whether from third-parties, the Utilities or storage), and the Utilities are obliged to deliver it to CFY customers. When actual demand varies from the forecast, CFY suppliers still have to meet demand or make accommodation for excess, and the Utilities still have to deliver what is demanded and manage their storage and delivery systems.

[61] On exceptions, the RGS assert they are not disputing the Utilities' allocation of "*storage capacity*," but their allocation of "*delivery rights.*" RGS BOE at 4 (emphasis in original).

Additionally, while neither CFY customers (whom RGS claims[62] constitute about 4% of the Utilities system load) or Rider FST accounts (which "comprise 6.694% of the total system delivery for [Peoples Gas]," Vanguard Ex. 3 at 7), have daily meters, Rider FST, but not Rider AGG, contains the following remedial provision in the event of customer abuse of delivery rights:

> The [Utility] reserves the right to limit the daily and monthly volumes of customer-owned gas delivered for the customer's account to the [Utility] when, in the [Utility's] sole judgment, the customer's deliveries are excessive in relation to the customer's gas requirements and may cause an adverse affect on system operations.

PGL-NS Ex. TZ-3.2.

Also, while we agree with the RGS that the Utilities' speculative scenario of CFY suppliers depleting their entire inventory by mid-December is commercially unreasonable (id. at 15) some of the RGS' proposed winter minima (15% of total storage *capacity* at the end of January, zero in February) (PGL-NS Init. Br. at 208) are scarcely better. The Utilities would still need to manage delivery, storage, and, perhaps, withdraw their own stored gas to meet CFY customers' heating requirements. Moreover, despite characterizing their proposal as "Nicor-like," the RGS acknowledge that their proposal affords CFY more storage flexibility than does Nicor's scheme. RGS Init. Br. at 15. RGS's explanation that the Utilities' storage assets "support wider storage targets" than Nicor's is unsupported by evidence or even a description of the differences.

As for the differences between Rider FST and Rider AGG, large industrial customers present different challenges for the Utilities' systems than do residential and small commercial customers. As the RGS acknowledge, "[CFY] customers (residential and small commercial) use gas mostly for heating and do not have level year-round requirements." RGS Ex. 2.0 at 7. Many large industrial customers use gas year-round in their production processes or to make electric power and, consequently, have very different load profiles than CFY customers. Furthermore, Rider FST is designed for *end-user* customers, while Rider AGG is intended for *suppliers* to end-users[63]. Without addressing the differences in detail – since the RGS did not address them at all – the Utilities' rights and responsibilities[64], regarding, respectively, end-users and aggregators, are not the same. Additionally, Rider FST concerns standby service, purchased by FST customers, in part, to obtain storage rights different from those available to CFY and sales customers. Rider AGG has no standby provision. Thus,

[62] At RGS BOE at 16, RGS cites to RGS Ex. 2.0 at 9 for this statistic, which does not appear anywhere in RGS Ex. 2.0.
[63] Rider SVT applies directly to CFY customers.
[64] For context, it is the Commission's experience that residential end-users have little interest in how gas storage is allocated or accessed (and could do nothing directly about if they did have interest); they focus primarily on retail price for home heating. Large industrial customers, on the other hand, typically engage in sophisticated fuel management, including planned reliance on storage.

Rider FST end-user customers, but not Rider AGG suppliers, can demand delivery of Utility gas, which affects Utility storage and balancing. In sum, The Utilities do not have to manage storage and delivery identically for all customer types (although the rates for all customers must be appropriately cost-based).

b) Aggregation Balancing Gas Charge (ABGC)

As noted above, the ABGC is a monthly charge through which the Utilities recover the costs of off-system storage and daily balancing service from CFY customers. It is recalculated monthly. The Utilities propose to assess the ABGC directly to CFY customers instead of to CFY suppliers. PGL-NS Ex. TZ-1.0. CFY suppliers have requested this change because fluctuations in the ABGC have made it difficult for them to offer fixed rate quotes to customers. No party opposes assessing the ABGC directly to CFY customers.

However, the RGS assert that if CFY suppliers' storage rights are not put on par with sales customers' storage rights in the manner the RGS seek, "the costs that flow through the ABGC need to be significantly reduced or the ABGC needs to be eliminated altogether…CFY suppliers and customers are paying the exact same storage related costs as…sales service customers." RGS Init. Br. at 10. Thus, as the RGS see it, they pay as much through the ABGC as sales customers pay through the Non-Commodity Gas Charge ("NCGC")[65] component of the Gas Charge, but receive inferior storage rights.

The Utilities reply that they incur costs to provide storage and daily balancing services to CFY customers, based on the firm storage and related transportation services the Utilities purchase from ANR Pipeline Company ("ANR") and Natural Gas Pipeline Company of America ("NGPL"). The Utilities aver that they could not provide such services for CFY suppliers unless these costs are incurred. They maintain that there "is no reason any customer class should get free balancing and storage service from the Utilities." PGL-NS Init. Br. at 209. The RGS respond that "the of…balancing…is only worth fractions of a cent per therm."[66] RGS BOE at 2.

Commission Conclusion

The Commission approves the proposal to directly charge the ABGC to consumers, who are apparently paying that charge indirectly anyway, through their CFY charges.

We will not reduce or eliminate the ABGC. Balancing service is provided in return for payment of that charge. As the Utilities state, "deliveries and requirements will vary on a daily basis. Under CFY, the Utilities assume responsibility for daily balancing…and not requiring daily metering." PGL Ex. TZ 1.0 at 49. With regard to the

[65] As the RGS describe it, "[t]he difference between the NCGC and the ABGC is that the ABGC is designed to exclude the cost of interstate pipeline transportation necessary to support sales service." RGS Init. Br. at 10. The Utilities' tariff language is as follows: "This charge is equivalent to the NCGC, less any costs not associated with balancing or storage." PGL Ex. VG-1.1 at 29.

[66] Peoples Gas's average ABGC over the 12 months ending in July 2007 was 3.46 cents/therm. PGL-NS Ex. TZ-2.0 at 50.

off-system storage component of the ABGC, CFY suppliers are certainly receiving such services. *E.g.*, id., at 50. What the RGS do not receive, to a degree they would prefer, is control over those services. "Suppliers are paying the ABGC and do not want the [Utilities] to control decisions concerning the underlying storage and balancing assets." RGS Ex. 2.0 at 10. Such control issues are addressed in connection with RGS's proposed Rider AGG (above) and with pipeline capacity assignment (below). The ABGC is an appropriately cost-based rate for which the Utilities supply approved services, and we will not diminish it as a remedy for purportedly insufficient control of the underlying assets.

c) Pipeline Capacity Assignment

In the event that their proposed Rider AGG is rejected (as it is, above), the RGS recommend that we direct the Utilities to release "capacity associated with the assets that flow through the ABGC, [which]…include off-system leased storage assets and the pipeline capacity necessary to deliver gas from those storage assets to the [Utilities]." RGS Init. Br. at 17. More particularly, the Utilities would "release storage capacity on a one-year recallable basis and pipeline capacity on a month-to-month recallable basis." Id. In other words, the RGS and other CFY suppliers would, in practical effect, sublease the storage and pipeline capacity that the Utilities lease from ANR and NGPL[67] and the Utilities could choose to "recall," or use, any storage or pipeline capacity the CFY supplier elected not to use. RGS lists three other utilities that offer capacity release options. RGS Ex. 2.0 at 9.

The Utilities counter that the capacity release process "would require participation in one or more interstate pipeline capacity release programs…[that] generally are subject to posting and bidding." PGL-NS Ex TZ-2.0 at 49. Accordingly, they argue that "releasing relatively small amounts of capacity to suppliers for customer pools that change monthly would be" administratively burdensome. Id. Additionally, the Utilities discount the usefulness of the recall rights the RGS would attach to capacity release. "By the time the Utilities discover that gas is not being delivered, they have missed the timely nomination deadline…purchasing gas after an intra-day recall is relatively difficult and costly." Id. Furthermore, the Utilities allege, capacity release, like RGS' other proposals, lessens the Utilities' control over the storage assets they manage for all customers. PGL-NS Ex. TZ-3.0 at 28.

Commission Conclusion

The Commission will not require capacity release. The principal response of the RGS to the Utilities' explanation of excessive administrative burden is to name a handful of gas utilities that offer capacity release. The actual offerings of those utilities are not described and, indeed, RGS' own proposal is not fleshed out (in contrast to the RGS' proposed Rider AGG). We are persuaded by the Utilities testimony (summarized

[67] RGS alternatively suggests a permutation on capacity release, by which the CFY suppliers would receive storage services based on the tariff rights the Utilities receive from off-system pipelines, with actual storage provided by Peoples Gas at Manlove. Thus, CFY suppliers would get Manlove storage under the terms and conditions applicable to off-system storage.

above) that capacity release involves a degree of complexity that the RGS have simply not addressed, either through evidence or their post-hearing arguments. This is not to say that capacity release is (or is not) an unwelcome idea. But the record presented here does not, by a considerable degree, furnish the requisite detail that could permit the Commission to impose a capacity release requirement.

d) Customer Migration

Customer migration occurs when a customer switches from one supplier to another, from the Utilities to a supplier, or from a supplier to the Utilities. RGS Ex. 2.0 at 10. The amount of seasonal storage capacity allocated to each supplier is based on the estimated load of the customers served by that supplier. Under the Utilities' current CFY storage program, the amount of available storage capacity allocated to each supplier is fixed prior to the start of the withdrawal period in November. The RGS assert that this can leave them with insufficient storage if a significant number of customers migrate to them after the withdrawal begins. A supplier's load would increase, but the amount of storage available to meet that load would remain static. The RGS also allege that their ability to use storage to take advantage of seasonal hedging is lessened. RGS Ex. 1.0 at 20. Furthermore, since customers and suppliers pay for storage through base rates and PGA charges, the RGS contend that storage capacity should follow customers when they change suppliers. Accordingly, the RGS proposed the following language in their Rider AGG:

> In the event that Supplier's storage capacity level increases significantly in any given month due to changes in the supplier's customers annual volumes, Supplier may purchase from Peoples storage inventory gas at then current first of the month price index published in Inside F.E.R.C.'s Gas Market Report for Chicago City Gate to enable the supplier to meet its minimum storage inventory levels as set forth below. Corresponding, in the event that supplier's storage capacity level decreases significantly in any given month due to changes in the supplier's customers annual volumes, supplier may sell to Peoples storage inventory gas at then current first of the month price index published in Inside F.E.R.C.'s Gas Market Report for Chicago City Gate to enable the supplier not to exceed its maximum storage capacity level. In any case, upon reasonable notification, Peoples at its sole discretion may require a supplier to purchase or sell storage inventory gas under the same price guidelines as outlined in this paragraph to meet prescribed storage inventory levels as set forth below.

RGS Ex. 2.1

The RGS claim that the foregoing text "is consistent with Nicor's treatment of storage capacity when customer migration impacts a supplier's obligations." RGS Init. Br. at 20. Although this language appears in the RGS' proposed Rider AGG, the RGS says that it "would also work under the Company's current program." Id.

The Utilities acknowledge that they do not reallocate storage among CFY suppliers during the withdrawal season. They state that they have designed the CFY program so that "withdrawals occur in a measured way over the course of the winter with appropriate adjustments for weather." PGL-NS Ex. TZ-2.0 at 51. "[I]t would not be practical to allow adjustments to inventory because this could entail winter injections or purchases and sales of gas by the Utilities to adjust the inventory balance." Id.

Commission Conclusion

The Commission approves the RGS' request for reallocation of storage during the withdrawal season, though we will not adopt the RGS' proposed textual revisions for the Utilities Rider AGG. The concerns of the RGS are valid and a reasonable remedy is readily available, while the corresponding burden on the Utilities is minimal. When storage capacity follows the customer, the potential that a competitive provider will have insufficient storage, or, more likely, pay a penalty for excess use of storage, is obviated. The Commission is not inclined to discourage competitive switching by adding unnecessary risk to the cost structure of alternative suppliers. Moreover, customers should not forfeit storage capacity when switching suppliers during the withdrawal season. Conversely, the Utilities do not need to retain storage rights for customers they no longer serve.

The Utilities' aversion to withdrawal season gas purchases, when prices are likely to be higher, is understandable, but we do not assume that the Utilities will need to make significant withdrawal season purchases with the RGS proposal in effect. We find it likely that virtually all changes in a CFY supplier's volume will be associated with the movement of *existing* accounts among providers. The Utilities provide storage and balancing for both RGS customers and sales customers, so the overall quantity of gas to be stored and balanced should remain essentially constant, except for new customers, whom either the Utilities or CFY providers will need to serve. Nor will the Utilities have to develop new information systems to accommodate storage reallocation during withdrawal season. The Utilities already recalculate monthly storage allocations as CFY customers change suppliers during the injection season (PGL-NS Ex. TZ-2.0 at 51) so they have information and billing systems in place to process and allocate CFY-affiliated storage during the winter.

However, the Commission finds that RGS's proposed text, quoted above, does not reallocate storage to account for customer migration. Rather, it is entitled a "Storage Purchase in Place/Cash-Out" provision, by which a CFY supplier will have an option to purchase or sell storage gas at a predetermined price. Whatever merits this provision might have in another context, it does not reallocate storage capacity in response to customer migration, which is what the RGS request. Indeed, the provision would apparently not reallocate storage at all if customer migration did not "significantly" alter the CFY supplier's capacity.

On exceptions, however, the RGS defend their proposal as mechanism for transferring stored gas along with storage capacity, in order to more practicably supply fuel to migrating customers. RGS BOE at 30. Staff "does not oppose" such gas transfer, at market price, "when customers migrate between the [Utilities] and a marketer." Staff RBOE at 63. The Utilities oppose the RGS provision, calling it

"complicated and convoluted." PGL-NS RBOE at 91. The Commission finds that the RGS' rationale for transferring gas along with storage capacity for migrating customers is reasonable, but RGS's proposed text does not address such transfer.

Accordingly, we will require the Utilities to perform the same storage reallocations during the withdrawal season that they perform during the injection season, as described by Utility witness Zack. This will minimize the changes required of the Utilities to accommodate customer migration to CFY suppliers. Additionally, any gas in storage for the migrating customers shall be transferred with the pertinent storage capacity, at the applicable price set forth the quoted text from RGS Ex. 2.1 above. Because that gas will already be aligned with the migrating customer's usage, the CFY supplier will not have to purchase additional gas during the heating season.

e) Month-End Delivery Tolerance

In the event their proposals for a revised Rider AGG and capacity release were rejected (as they are, above), the RGS request that their month-end gas delivery tolerance be expanded to 10% or, preferably, eliminated entirely, to provide greater flexibility. RGS Ex. 2.0 at 14. Deliveries within the tolerances are not subject to penalty, even though they exceed established limits. The Utilities presently allow a 2% month-end delivery tolerance, which they have proposed to expand to 5% in these proceedings[68]. PGL-NS Ex. TZ-1.0 at 29. The RGS argue that customers can be hesitant to use their full daily delivery allowance of 10% for fear of exceeding smaller monthly limits.

The Utilities acknowledge that CFY suppliers are allowed a 10% daily delivery balance, but insist that month-end tolerances should nevertheless remain smaller, to match the Utilities' overall operating plan. PGL-NS Ex. TZ-3.0 at 26. They maintain that their proposed increase of the month-end tolerance to 5% is sufficient and, accordingly, oppose the RGS' request for a 10% allowance. Staff also opposes the RGS' proposal, because it is "more difficult for the utility to plan its purchases as well as their storage injections and withdrawals if the monthly tolerance is too large which would result from adopting the RGS proposal." Staff Init. Br. at 260.

Commission Conclusion

The Commission concludes that the Utilities' proposed increase of the month-end delivery tolerance is an adequate response to the RGS' request for greater flexibility. The RGS have not rebutted the contentions of the Utilities and Staff that the Utilities themselves have month-end obligations and that an expanded tolerance for CFY suppliers would make fulfillment of those obligations more burdensome.

[68] That is, the current month-end delivery tolerance "in the current Rider AGG is plus or minus 2% of the sum of the Required Daily Delivery Quantities ('RDDQs') for each day during the month. The RDDQ is the Company's estimate of the usage of pools of customers served by CFY suppliers." RGS Init. Br. at 20.

f) Working Capital Related to System Gas Costs/Monthly Customer Aggregation Charge

Since CFY suppliers incur working capital costs associated with gas stored on behalf of their customers, they aver that "it would be inappropriate to allocate the Company's working capital costs to CFY customers because they do not purchase or consume" Utility-supplied gas. RGS Init. Br. at 22. The Utilities agree and "propose to include a credit from working capital in the CFY customer Aggregation Charge." NS-PGL Init. Br. at 211. The resulting credit is $1.48 per North Shore customer and $2.26 per Peoples Gas customer. PGL-NS Ex. 3.0 at 31. The North Shore credit leaves a three-cent per customer per month aggregation charge, and the Peoples Gas credit effectively eliminates Peoples Gas's aggregation charge and leaves an $0.83 per customer per month credit. The RGS propose that the credit be applied to the ABGC, which the RGS describe as "competitively neutral" because of the way CFY suppliers incur and recover gas storage-related working capital costs on their customers' behalf. RGS Rep. Br. at 14. Moreover, "an offset to the ABGC would allow customers to more easily compare the costs of participating in CFY and sales service." Id.

Peoples Gas prefers that the remaining credit "simply become a credit on the bill." PGL-NS Ex. 3.0 at 31. Peoples Gas opposes applying the credit to the ABGC, "because the ABGC is a gas cost and the credit relates to base rate costs." Id. Further, the Utilities argue, "[a]pplying the credit to the ABGC would affect the gas cost reconciliation with revenues that are not recoverable gas costs. Also, the credit is a per customer credit while the ABGC is a per therm charge and it is unclear how the per customer credit would be integrated into the per therm ABGC." PGL-NS Rep. Br. at 163-64.

Commission Conclusion

The Commission approves the parties' agreement to reduce the customer Aggregation Charge in the amounts described above. We reject the RGS' proposal for applying any excess credit against the ABGC. The Utilities are correct that the proposal is not sufficiently developed on the record, so that the credit can be accommodated in the per-therm ABGC. The RGS tacitly acknowledge this, as reflected in their subjunctive recommendation "that the credit apply to the ABGC *or in a competitively neutral manner* such that the credit offsets a CFY customer's supply portion of the bill and not the delivery portion of the bill." RGS Rep. Br. at 14 (emphasis added).

It is implicit in this discussion that the monthly aggregation charge is not formally being eliminated, although that is the practical outcome of the working capital credit applied against the aggregation charge. The RGS did not address elimination in their reply brief, and we cannot say, on the record as it stands, that the costs identified by the Utilities (PGL-NS Init. Br. at 212) should not be recovered (even though offset) through the Aggregation Charge.

2. Customer Enrollment

a) Customer Data Issues

The Utilities maintain that they have made four proposals regarding customer data that satisfactorily address concerns raised by CFY suppliers. First, they propose to provide customers lists, excluding customers on the Utilities' "do not contact" lists, to CFY suppliers without customer consent but pursuant to a contract with the Utilities. The customer list would include customer names and addresses, and whether the customer is in service classification 1N or 1H, but it would not include customer telephone numbers. The Utilities will not do this more than once every six months. The RGS and NAE accept this limitation. RGS Ex. 2.0 at 15; NAE Rep. Br. at 3.

Second, the Utilities have proposed to provide, pursuant to a contract, more detailed customer information to CFY suppliers in two tiers. Tier 1 would not include any customer information and would not require customer consent. Tier 2 would include customer information but would require customer consent. Tier 2 information would include name, billing address, premises address, usage, type of meter reading and other reading dates. Neither tier would be provided to CFY suppliers for free.

If directed to do so by the Commission in these proceedings, the Utilities would, third, provide a customer's payment history to a CFY supplier, if the supplier, among other things, warrants that it has that customer's consent to obtain that customer's payment history and indemnifies the Utilities against any claim that the supplier does not have such consent; and, fourth, the Utilities would provide a customer's past due amounts to a CFY supplier if the supplier complies with the same consent and indemnity requirements.

Commission Conclusion

As a general proposition, the Commission will require the Utilities to supply the information described in the four categories above, thereby providing the mandate the Utilities apparently seek[69]. That said, RGS and NAE raise several specific issues concerning the manner in which the pertinent data would be furnished. Consequently, the general approval announced in this paragraph is modified by, and subject to, the specific conclusions articulated in the subsections of this Order below.

Also, the Utilities and NAE appear to disagree about the inclusion of phone numbers among the data that must be disclosed. The Commission is not inclined to abet telemarketing and will not require disclosure of phone numbers. Alternative providers can use mailings to attract inbound calls and email communication.

[69] On exceptions, Staff objects to the provision of customer lists without customer consent, reminding us that we rejected such non-consensual disclosure in Nicor. Staff BOE at 88-89. The Commission is willing to mandate a different result in these proceedings, however, because NAE has presented a more persuasive case concerning the public nature of names and addresses and the additional cost of procuring such information from commercial sources, with potentially inferior accuracy. We certainly share Staff's privacy concerns, and we have endeavored to protect customer privacy without diluting the customer benefits associated with expanded and sustainable choices among gas providers.

Similarly, NAE disagrees with Staff (Staff Init. Br. at 261) and the Utilities (PGL-NS Init. Br. at 214) about prohibiting CFY suppliers from using customer information obtained from the Utilities for any "non-utility service" or "for any purpose other than in connection with gas service." The Commission believes that such a prohibition is appropriate, however. Our function is to oversee public utility services, not to promote non-utility marketing schemes or customer data sales, especially when we required transmission of certain customer data without charge (see below). Consequently, Utility contracts for information transfers should bar re-transfer of the data furnished for purposes other than provision of gas service. However, we do not, and cannot, preclude alternative providers from obtaining information directly from customers or other sources. Any limits on the re-transfer of information provided directly by customers and other sources would be determined by the information provider and the CFY supplier.

i.) Timing of Data Transmission

The RGS assert that customer data is needed before a CFY supplier agrees to furnish service, so that the supplier can check the customer's creditworthiness. RGS Rep. Br. at 15. Consequently, the RGS want the Utilities to furnish data as soon as proof of customer consent is obtained and presented. Id. Vanguard takes the same position. Vanguard Init. Br. at 9-10. So, too, does NAE, who adds that pre-enrollment receipt of customer data facilitates the single-billing option, i.e., direct and unitary billing by the alternative supplier, because customers in arrears to a utility cannot be single-billed. NAE Init. Br. at 5.

We conclude that customer data should be provided to the alternative gas supplier as soon as is practicable after the supplier presents valid customer consent to the Utilities. The Utilities cannot insist that the customer be "active and flowing" or even committed to receiving service from the alternative supplier. The pertinent customer information is of its greatest use to the supplier before that commitment has been made, to assess creditworthiness.

ii.) Data Fees

The RGS purport in their initial brief that the Utilities are willing to supply customer data without cost. RGS Init. Br. at 23. The Utilities deny this, albeit without supporting argument[70]. PGL-NS Rep. Br. at 164. Consequently, we will treat this as a disputed issue. NAE avers that the Utilities already keep the Tier I and Tier II customer data "for their own use, and the costs of maintaining that information is recovered from sales and transportation customers through the Utilities' rates [*citing* Tr. at 633 (Zack)]. The Companies should not be permitted to double-recover those costs by charging suppliers for access to that information." NAE Rep. Br. at 6. Second, NAE stresses that the pertinent data are "ultimately the ***customer's*** data." Id. (emphasis in original). Third, the fees imposed on CFY customers and suppliers "subsidize the administration

[70] In fact, we cannot be certain that the Utilities object to providing customer lists without charge. Their reply brief only discusses Tiers 1 and 2 data.

and maintenance costs of that program, which should include mechanisms for allowing customers to provide their data to suppliers." Id.

The Commission will not allow the Utilities to impose a charge for furnishing either customer lists or Tier 1 data. The Utilities are not commercial data supply entities. Customers have willingly submitted the pertinent data to them in their capacity as monopoly providers of gas delivery service, operating under certificates of public convenience and necessity. At the same time, the Utilities compete with CFY providers to supply gas. Although gas supply is performed without markup, sole access to the customer, as a bundled provider, has value for, among other things, bill inserts and cross-promotions. Moreover, as NAE points out, the Utilities receive compensation for maintaining customer data though base rates. We doubt that the trivial cost of electronically transmitting that information to CFY suppliers would exceed rate elements collected by the Utilities. Therefore, we conclude that the basic data in customer lists and Tier 1 should be furnished without charge. However, the Utilities can insist on providing the data pursuant to a contract with the alternative supplier, setting out terms and conditions, as described in NAE Cross-Ex. 2.0 (Zack). Also, if the supplier wants data in other than electronic form, the Utilities may impose a charge.

Tier 2 data, payment history, and arrearage data are a different matter. As we determine below, these data categories will involve customer consent. Consequently, the Utilities will have to do more than electronically transfer information they have already gathered with existing information system configurations. They will also have to receive and monitor customer consent information. The Utilities can require compensation for that service.

As recommended by NAE (NAE BOE at 4) and supported by Staff (Staff RBOE at 64) we direct the Utilities to file a tariff describing in sufficient detail how customer consent will be monitored by the Utilities and how Tier 2 data will be transmitted to the requesting entity. The tariff should be accompanied by supporting cost data justifying all included charges. No duplication of cost recovery accomplished through any other Utility tariffs should occur[71].

b) Evidence of Customer Consent

There is consensus among the parties that customer consent should be a prerequisite for obtaining customer payment and arrearage information. There is no consensus regarding the mechanisms for accomplishing this. Staff cautions that the customer must "explicitly authorize[] in clear, non-technical terms, the marketer to have this information." Staff Init. Br. at 262. For their part, the Utilities want the Commission's unambiguous imprimatur for a customer consent mechanism, so that they are not caught up in disputes regarding the legitimacy on consent. PGL-NS Rep. Br. at 165. In particular, they seek indemnity from damage claims. They also raise

[71] That said, we will not specifically prescribe how the Utilities should avoid cost recovery duplication, as NAE proposes ("providing tariff reductions to existing CFY riders to the extent that the monitoring costs are duplicative," NAE BOE at 4). The Utilities may be able to draft a Tier 2 information tariff that, by itself, avoids duplicate recovery.

additional issues regarding third-party verification of consent and Utility access to CFY supplier form contracts. PGL-NS Init. Br. at 214.

The RGS propose language drawn from one of their members, supported by general comments about the appropriate parameters of customer consent. RGS Init. Br. at 25. But the RGS then appear to endorse "the Nicor process." RGS Rep. Br. at 17. NAE initially proposes certain language (NAE Init. Br. at 10) which it later describes as "consistent with" Nicor tariff sheets attached to its Reply Brief. NAE Rep. Br. at 8. The tariff sheets are far more detailed, and it is not clear to the Commission whether NAE is recommending only the limited text in its Initial Brief or the more comprehensive text attached to the Reply Brief.

Commission Conclusion

As the Commission perceives it, the parties have submitted a hodge-podge of partial recommendations, generic concurrences and broad principles, apparently expecting us to sort things out for them. We are not inclined to do so. Customer consent involves important and potentially conflicting issues of consumer privacy and autonomy, which require careful and comprehensive drafting to ensure genuine consent and avert disputes among stakeholders. Assuming solely for the sake of argument that a rate-setting proceeding is the appropriate context for reviewing the requisite procedures and written agreements essential to customer consent, it is incumbent upon the interested parties – particularly those who want access to information – to provide clear, comprehensive and detailed recommendations. Given the sheer volume of issues and evidence to address in these rate cases, the Commission will not accept the burden of drafting contracts, any word of which can elicit further disputes.

Accordingly, we will simply adopt principles that must be embodied in the requisite customer consent process. The Utilities can consult with other stakeholders to arrive at consensus terms and conditions incorporating those principles, or they can simply incorporate the principles in their proposed customer consent provisions. First, as the Utilities request, they should not be responsible if there is any dispute between a CFY supplier and its customer about the scope or effectiveness of a customer's authorization to the CFY supplier to obtain payment history or past due payment data from a Utility. Second, the CFY supplier shall indemnify the Utilities against any customer damage claim if the CFY supplier receiving the data does not have the requisite authorization, or if the customer revokes the authority prior to the occurrence of a purportedly damaging error or omission. Third, customer consent must be unequivocal and all matters to which the customer consents must be stated in unambiguous and everyday language. Fourth, a customer's written signature is unnecessary as proof of consent, so long as other satisfactory indicia of consent are provided. Fifth, third-party verification of customer consent is not required.

The Commission rejects NAE's request (NAE BOE at 4-5) that the Utilities be required to supply customer payment and arrearage information before provisions regarding evidence of customer consent are in place. We do not want to open a temporary window of opportunity for the very non-consensual disclosure we intend to preclude. However, so that there is no foot-dragging in the process of establishing

consent procedures, the Commission directs that the Utilities have customer consent processes in place and operational no less than 45 days after entry of this final Order[72].

c) Minimum Stay Requirement

The Utilities initially proposed to continue requiring a CFY customer returning to Utility sales service and not selecting another CFY supplier within 60 days to remain on Utility sales service for a minimum of one year before being again eligible to switch to CFY service. PGL-NS Ex. TZ-2.0 at 57. Subsequently, the Utilities modified their proposal to require retention of a customer that does not select another CFY supplier within 90 days. PGL-NS Ex. TZ-3.0 at 33. The Utilities offer three reasons for this requirement. First, they assert that it provides reasonable certainty to their gas supply planning. Second, they argue that it prevents customers from switching back and forth between CFY suppliers and the Utilities to take advantage of temporary price fluctuations. Third, they point out that it is not substantively different from the minimum terms provisions that CFY suppliers insert in their own contracts.

The RGS respond that a minimum stay requirement is anticompetitive and limits customer choice. RGS Init. Br. at 26. They challenge the Utilities' supporting rationales, stating that the movement of individual residential customers will not upset the Utilities' supply planning for approximately one-million customers. The RGS also contend that individual residential customers cannot exploit arbitrage opportunities, given the lag in the switching process. Id. The RGS recommend that customers be allowed two switches per year, with no minimum stay requirement. If that proposal is rejected, the RGS requests that the time a customer has to switch after returning to Utility sales service be extended days to 120 days before the one-year minimum stay requirement is applied. RGS Ex. 2.0 at 27.

Commission Conclusion

We agree with RGS that the arbitrage potential for residential and small commercial customers is minimal, and that overall system supply is not meaningfully affected by switching by such customers. The more substantial concern is that the resources of both the CFY suppliers and the Utilities could be wasted processing switches by customers temporarily enticed by marketing strategies. The RGS clearly understand this, since they impose their own one-year contracts and exit fees to discourage frequent switching. RGS Init. Br. at 27. In order to balance that concern with the benefits of customer freedom, the Commission approves the RGS's compromise proposal to allow switches away from the Utilities within 120 days before the one-year minimum may be imposed.

3. Rider SBO

a) Billing Credit

NAE proposed that the Utilities provide CFY suppliers a credit for single billing under Rider SBO (Single Billing Option), to reflect costs avoided by the Utilities when

[72] This deadline shall apply without exception - irrespective of the filing of an appeal of this Order by any party and irrespective of the progress of any attempt at consensus among the stakeholders.

they do not have to issue a bill for their distribution charges. NAE Ex. 1.0 at 7-12. The Utilities initially opposed any credit, but later agreed to provide a 33-cent per customer monthly credit for CFY suppliers billing under Rider SBO. PGL-NS Ex. TZ-3.0 at 31. The proposed credit reflects the Utilities' estimate of postage and paper costs. Tr. at 624 (Zack).

However, NAE maintains that there are additional billing costs (e.g., quality control and information technology) not removed by the Utilities' proposed credit. The parties agree that there is insufficient information available to accurately quantify such costs. NAE therefore recommends that the Utilities perform an embedded cost study to identify all billing costs. NAE notes that we have required such studies in previous proceedings. As a secondary alternative, NAE requests an avoided cost study. Staff supports a cost study. Staff Rep. Br. at 110.

The Utilities object to performing either study. They stress that no supplier is actually using the single billing option. They caution that a study might uncover additional costs that could even reduce the 33-cent credit.

Commission Conclusion

The Commission's policy is to align costs with charges and, in general, we prefer that comprehensive information be available for rate-making. Accordingly, we direct the Utilities to conduct an avoided cost study (which we understand to be the less burdensome alternative) regarding their billing costs. The Utilities may, at their discretion, perform an embedded cost study instead, should they believe it might identify costs to be added to Rider SBO. In either case, the study results should be provided to the Commission in 120 days, and Rider SBO should then be revised as necessary to reflect those results. For now, the 33-cent credit should be included in Rider SBO.

b) Order of Payments

When a customer receiving gas from an alternative supplier and distribution service from one of the Utilities makes partial bill payment, the funds are allocated between the supplier and the Utility. Until now, the allocation, or "order of payments" has been different under Rider SBO, where the supplier bills and collects all charges, than under the Utilities' single bill, where the Utility bills and collects all charges. Under Rider SBO, the Utilities get all their charges paid before the CFY supplier receives any payment. In contrast, under the Utility (LDC) single billing option, the order of payment is Utility past due charges, then CFY supplier past due charges, then Utility current charges, then CFY supplier current charges.

NAE, supported by the RGS, requests that the order of payments under the Utility single billing option be used for SBO as well. The Utilities recommend the reverse – that the SBO order of payments, by which all funds go first to Utility charges (current and past due) should be incorporated in the LDC option. In short, in single-billing situations, CFY suppliers request greater sharing of partial payments and the Utilities request none (unless the partial payment exceeds all Utility charges).

The CFY suppliers argue that the Utilities' proposition disadvantages them absolutely by increasing their risk of non-collection, and relatively, by reducing the Utilities' risk. The Utilities counter that the Rider SBO order of payments was approved in Docket Nos. 01-0469 and 01-0470, while the Commission has never addressed the order of payments under the LDC billing option.

Commission Conclusion

As the Commission views it, the Utilities' intention is to reduce their own collection risk by shifting it to the alternative gas suppliers. The likely result is an incrementally adverse impact on supply competition, as the competitors either absorb collection losses or adjust rates upward. That would be inconsistent with our policy of expanding customer choice, without alleviating any problem indentified by the Utilities – who designed the LDC payment order themselves and ascribe no difficulties to it. As for our actions in Docket Nos. 01-0469 and 01-0470, we were not presented with the issues or choices framed in the present dockets. The Commission now has the opportunity to refine our approach to payment allocation. We conclude that the order of payments in the Utilities' LDC single-billing option should also apply under Rider SBO.

c) NSF Checks

Under the Utilities' existing practice regarding the return of customer non-sufficient funds ("NSF") checks, when one of the Utilities issues a single bill and receives a customer check, the Utility credits the appropriate funds to the CFY supplier, and if the check is later determined to be NSF, the Utilities do not try to recover the uncollected funds from the CFY supplier. Correspondingly, if a CFY supplier billing under Rider SBO were to receive a check, the supplier would pay the appropriate funds to the relevant Utility, and if the check were later determined to be NSF, then the Utility would not return any portion of the funds to the CFY supplier that accepted the NSF check for payment. NAE contends that this arrangement favors LDC single billing and discourages the use of SBO.

NAE wants to alter the foregoing practice so that when either party – supplier or Utility - determines that a check is NSF, it will receive reimbursement from the other party, to whom it has already transferred funds. Thus, instead of the suppliers and the Utilities each bearing the burden of their own customers' bad checks, they would share that burden, in that each would remain unpaid (unless or until the customer pays the arrearage later).

Commission Conclusion

The issue is whether to promote provider responsibility or debt sharing. We will resolve that issue by rejecting NAE's proposal. Whether the pertinent customer is single-billed by the supplier or the Utility, that customer will be the supplier's customer, in the sense that the supplier will have marketed the customer and vetted the customer's creditworthiness. The Utilities' role will only include the provision of tariffed services (distribution, and perhaps billing) to facilitate fulfillment of the supplier's

agreement with the customer. The Commission sees no convincing reason why the Utilities should share bad debt risk when they have an obligation to provide service and no control over customer selection.

4. Purchase of CFY Supplier Receivables

The RGS propose a Purchase of Receivables ("POR") program, under which the Utilities, upon request by a CFY supplier, would purchase the supplier's accounts receivable associated with natural gas supply. In other words, the Utilities would assume responsibility for collecting whatever is owed for gas service by the CFY supplier's customers, with any shortfall borne by the Utilities.

The RGS assert that the Utilities would be "made financially whole by recovering the uncollectible amounts and program administration expenses through one of two options: 1) a discount rate equal to the utility's actual uncollectible amount that offsets the payments to the supplier and is subject to a periodic reconciliation process; or 2) an element of the utility's base rates." RGS Rep. Br. at 19. That is, under the first option, the Utilities would remit to CFY suppliers something less than the face amount of the suppliers' receivables, then hope that the difference (i.e., the discount) equaled or exceeded permanently uncollectible debt. However, the RGS prefer that no discount be included in their proposed POR regime. The Utilities would simply pay face value for receivable accounts. Under the second option, the Utilities would increase their uncollectible expense to account for the additional bad debt assumed from CFY suppliers.

The RGS argue that their proposal would remedy several inequities they perceive. They stress that, at present, customers cannot be disconnected for non-payment of an alternative supplier's gas charges, which undermines the suppliers' collection leverage. If receivables were assumed by the Utilities, the RGS believe disconnection would be permissible because the pertinent arrearages would be owed to the Utility involved. They further assert that CFY customers currently "pay twice for debt collection efforts" because both the supplier and the Utility have debt collection costs built into their rates. RGS Init. Br. at 31. They also contend that a POR regime would increase overall efficiency, by eliminating any need for separate credit inquiries and collection efforts by the CFY supplier and the Utilities.

The RGS additionally emphasize that POR programs are in place in other jurisdictions, involving both gas and electric utilities. Id. at 36. Moreover, the RGS point out, a bill passed by the General Assembly and signed by the Governor in November 2007, Public Act 095-0700 ("PA 0700"), expressly requires ComEd and the Ameren Companies to offer a POR program in connection with electricity services. Id. at 37; RGS BOE at 24.

The Utilities rejoin that the RGS' proposal "is an inappropriate attempt to shift business risks from CFY suppliers to the Utilities and utility customers." PGL-NS Init. Br. at 219. Additionally, they underscore that PA 0700 does not apply to gas utilities and expressly requires "`a just and reasonable discount rate to be reviewed and approved by the Commission after notice and hearing. The discount rate shall be based on the electric utility's historical bad debt and any reasonable start-up costs and

administrative costs associated with the electric utility's purchase of receivables.'" PGL-NS Init. Br. at 221 (*quoting* PA 0700). In the Utilities' view, "[t]here are no facts in the evidentiary record upon which the Commission could determine an appropriate discount rate." Id. Similarly, the Utilities charge, if the Commission were instead inclined to adjust the Utilities' revenue requirements to reflect a POR, "there is no data in the record that would come close to providing a basis for calculating how much the Utilities' revenue requirements would need to be increased to offset the shift of risks, burdens, and expenses." Id. at 220.

Staff also opposes the RGS's POR proposal, stating that it may make the Utilities' business "more risky if the POR induces marketers to target customers that are at a high risk of default." Staff Init. Br. at 264.

Commission Conclusion

The Commission rejects the RGS' POR proposal. The RGS endeavor to frame the dispute arising from their proposal as a supplier-versus-utility match-up, as if customers were unaffected third parties. In fact, irrespective of the compensatory mechanism selected, whether the RGS' preferred "zero discount," an actual discount, or an adjustment to the Utilities' revenue requirement, ultimate responsibility for CFY bad debt will shift to the Utilities' *customers*, including sales customers. The RGS understand this. "Under a zero percent discount POR program, the [Utility] recovers uncollectible and any start-up and administrative expenses from CFY customers and sales customers through base rates." RGS Rep. Br. at 25-26. The POR proposal thus shifts both the risk of CFY bad debt and CFY bad debt itself to all ratepayers, including those with no relationship with the CFY suppliers.

This shifting of responsibility is exacerbated by the discretion the POR program would confer on suppliers to avoid credit assessments before signing up customers. "It would no longer be necessary for CFY suppliers to examine customer payment histories or perform credit checks on potential customers because, under POR, CFY suppliers would be guaranteed of all their customers' receivables at a discounted rate [although, as already noted, the RGS offer no discount]." RGS Init. Br. at 33. The RGS view these circumstances as desirable, because they "bring[] choice to customers where it was previously unavailable." Id. The RGS is apparently referring to customers with unsavory credit histories--including, RGS acknowledges, customers with repeated arrearages for gas service. Tr. at 1025-26 (Crist). Such customers would indeed enjoy broad choice under the RGS' zero discount POR, since neither they nor the CFY supplier would have any stake in their accountability[73].

The General Assembly did not mandate POR for gas suppliers when it enacted PA 0700 for electricity suppliers. Although the Commission could infer from that omission that the General Assembly intentionally elected to treat the gas and electricity markets differently, the RGS claim that new legislation was required for electricity because of limitations imposed by subsection 16-103(c) of the Act, while no comparable

[73] In contrast, when there is a meaningful discount, the alternative supplier at least retains an interest in *monitoring* bad debt, so that it does not surrender its receivables too cheaply.

statute constrains our authority to order gas utilities to provide POR. RGS BOE at 25. However, subsection 16-103(e) only bars this Commission from requiring an electric utility to provide certain "tariffed services." Under Section 16-102 of the Act, "tariffed services" are defined as services for *retail customers*. In contrast, PA-0700 contemplates a POR tariff for "*retail electric suppliers*." (Emphasis added.) Accordingly, the RGS' statutory analysis does nothing to clarify the General Assembly's intentions or our own authority, absent specific legislation, to mandate POR[74].

In any event, the Commission concurs with the Utilities that the evidentiary record is insufficient to establish either an appropriate discount or an increased revenue requirement associated with a POR tariff. By comparison, PA 0700 contemplates a hearing before a discount rate can be set for an electric utility. As we understand that requirement, a detailed rate mechanism, supported by quantitative evidence, would be assessed. Here, there is only a concept, with no discount rate above zero even proposed, much less supported with evidence. Similarly, there is no quantitative evidence to sustain a revenue requirement adjustment. In a proceeding in which, by comparison, NAE requests a billing cost study, it would be inconceivable to alter revenue requirement without quantitative analysis.

5. PEGASysTM and Customer Information

PEGASys is the electronic bulletin board through which the Company conducts daily transactions with CFY suppliers. All parties, including the Utilities, agree that PEGASys needs improvement. The Utilities have already completed certain modifications and more are in progress. PGL-NS Init. Br. at 221-22. However, the Utilities envision completion of their improvements "no later than August 2008…and perhaps as early as June 2008." Id. at 222. The RGS and NAE both request an earlier completion date, suggesting 30 days after entry of this Order (that is, the first week of March 2008).

Commission Conclusion

The Commission certainly understands the interest of the RGS and NAE. PEGASys is a critical interface by which they conduct important elements of their business. To facilitate that business, the Commission would be inclined to establish an earlier deadline for the ongoing improvement, if we had a more granular evidentiary basis for doing so. The record does not indicate what specific work is under way or whether its pace can be accelerated. Nor is there evidence that the Utilities are stalling. We are reluctant to require faster action without knowing if that is reasonable.

We infer from Utilities' own declarations that the PEGASys improvements can be finished and operational by August 2008. Therefore, we will hold the Utilities to that projection. The enhancements described in the Utilities' testimony must be in place and functioning appropriately by August 15, 2008.

[74] Since we are rejecting POR for the specific reasons discussed in this Order, which do *not* include the absence of administrative authority to mandate POR for gas utilities without specific legislative authorization, the Commission does not need to – and does not – decide whether such legislative authorization is necessary.

E. Tariff Corrections and Clarifications

The Utilities have proposed five corrections and clarifications to their proposed transportation tariffs. Each is listed below. No party has objected to any of them. The Utilities also proposed three clarifications to their Terms and Conditions of Service. No party has objected to any of them. The Commission finds them reasonable, and they are approved.

1. Rider SST, Section F

The Utilities propose to add the following sentence to the end of the last paragraph in Section F: "For quantities that would be in excess of this limitation, the customer shall purchase gas under the Companion Classification in a quantity not to exceed the product of the SSQ times the number of days in the month minus standby service gas purchased during the month and any remaining quantity shall be Unauthorized Use."

2. Rider TB, Section A (Peoples Gas Only)

Peoples Gas proposes to add in Rider TB, Section A, Imbalance Coincidence Factor, a new sentence before the last sentence of the definition: "For purposes of determining the ICF, the Company shall use only Service Classification No. 4 customers' data."

3. Rider LST-T (Peoples Gas Only)

Peoples Gas proposes to delete the charge from Section B of Rider LST-T and add the non-charge language to Section J of Rider LST-T.

4. Rider SST, Section H

A proposed change to Rider SST, Section H, was made moot by the Utilities' proposed changes to Rider SST in their surrebuttal testimony.

5. Rider SST, Section K

Rider SST, Section K, addresses customers who do not yet have daily metering installed. There is a minimum AB requirement and a gas purchase obligation if the minimum AB is not met. The Utilities propose that the purchase price be 110% of the AMIP.

6. Rider TB, Section H and Rider P, Section G

The Utilities propose that the following be added to the second paragraph of Section H: "or increase the amount of the imbalance." A comparable change in Rider P, Section G, would be appropriate.

7. Terms and Conditions of Service

These matters are addressed in Section IX.D.8. of this Order.

XI. UNION PROPOSALS

Local Union No. 18007, Utility Workers Union of America, AFL-CIO (the "Local"), entered this proceeding as a representative of workers employed byPeoples Gas, but not by North Shore. According to the Local: Peoples Gas "is not currently meeting its obligations to acquire, train, and maintain an adequate workforce. As a result…[Peoples Gas's] current complement of on-staff resources is unable to handle its normal workload." Local Init. Br. at 2. These conditions, the Local alleges, limitPeoples Gas's ability to provide "safe, reliable and cost-effective gas service." Id. at 3. Therefore, the Local requests that the Commission take two actions: 1) direct Peoples Gas to adopt the Local's "One-For-One" workforce replenishment plan (the "Plan"), under which Peoples Gas will have to fill higher-skilled job vacancies with a qualified Local candidate, unless job obsolescence or infrastructure improvements dictate otherwise; and 2) require an independent audit of (a) work order response times and backlogs (inclusive of temporary repairs) at PGL, and (b) staffing levels among the utility workforce at PGL. Local Init. Br. at 5. PGL opposes both of the Local's requests.

A. One-for-One Replenishment Plan

The stated objective of the Plan is to preclude Peoples Gas from leaving senior positions unfilled (absent job obsolescence or overriding infrastructure improvements). Thus, Peoples Gas "would commit to replenishing any union vacancy with an internal Local… candidate." UWUA Ex. 1.0 at 8. More specifically, "[e]ach May 1, for example, Peoples Gas can release to [the] Local…a report that provides attrition figures by department and job classification. [Peoples Gas] could commit to routinely replenish vacant posts in a predictable cycle: with internal candidates (selected according to a set of pre-approved metrics, *i.e*., experience with [Peoples Gas's] operations and a supervisor's performance approval) on a set clock after a prescribed period of time has elapsed from release of the attrition report (*e.g.,* 90 days)". Id. at 19.

1. Scope of Commission Authority

As a threshold issue, Peoples Gas questions the Commission's authority to mandate the Local's plan for PGL's operations. Peoples Gas and the Local have a collective bargaining agreement ("CBA"), which is not under the Commission's purview. According to Peoples Gas, problems arising under the CBA would either be governed by the CBA's own grievance procedure or would be addressed under federal jurisdiction. Peoples Gas cites 29 U.S.C. § 160(k) (the National Labor Relations Board ("NLRB") has primary jurisdiction over disputes arising out of allegations of unfair labor practices); San Diego Bldg. Trades Council v. Garmon, 359 U.S. 236, 245 (1959); *see also* Marquez v. Screen Actors Guild, 525 U.S. 33, 49 (1998) (labor disputes fall within the primary jurisdiction of the NLRB in part to promote a uniform interpretation of the NLRA). Suits alleging violation of a CBA can also be brought in any U.S. district court with jurisdiction over the parties. 29 U.S.C. § 185(a). To address the Local proposal, PGL stresses, the Commission would need to decide CBA issues, *see* Tr. at 821 (Gennett); if we approve the proposal, the Local would "achieve through a Commission order what it has not been able to bring about through negotiation." PGL-NS Init. Br. at 228.

The Local objects to the Utilities' characterization of the Local's proposals as "labor relations" matters that should be addressed through CBA negotiations and grievance procedures, or through dispute resolution proceedings before a federal court or agency. Instead, the Local argues, its proposals lie squarely within the Commission's statutory power to ensure that utility operations promote employee and public health and safety. The Local relies upon Section 8-505 of the Act[75], which states:

> The Commission shall have power, after a hearing or without a hearing as provided in this Section…to require every public utility to maintain and operate its plant, equipment or other property in such manner as to promote and safeguard the health and safety of its employees, customers, and the public, and to this end to prescribe, among other things, the installation, use, maintenance and operation of appropriate safety or other devices or appliances, to establish uniform or other standards of equipment, and to require the performance of any other act which the health or safety of its employees, customers or the public may demand.

The Local asserts that the foregoing text authorizes the Commission to impose the Plan because "the failure to fill open vacancies among top-tier employees is preventing the timely implementation of permanent repairs of gas leaks, thereby leaving employees and the consuming public at risk." Local Rep. Br. at 6.

The Local also points to our authority in rate-making proceedings, derived from Section 9-201(c) of the Act[76], to "establish the…practices, rules or regulations proposed, in whole or in part, or others in lieu thereof, which it shall find to be just and reasonable." The Local believes that Section 9-201(c) empowers us to prescribe staffing and repair practices as conditions coincident to rate revision. The Local additionally cites Section 8-401 of the Act[77], which declares that "[e]very public utility subject to this Act shall provide service and facilities which are in all respects adequate, efficient, reliable and environmentally safe."

2. Commission Conclusion re: Scope of Authority

Peoples Gas is correct that we do not oversee collective bargaining or enforce the Peoples Gas-Local CBA or resolve disputes under the CBA's provisions. Peoples Gas is also correct that allegations concerning "unfair labor practices" are within the province of the NLRB or comparable state agencies that oversee labor-management. However, the Local is not requesting enforcement of the CBA or alleging an unfair labor practice. Rather, the Local seeks enforcement of the public and employee health and safety provisions of the Act[78].

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[75] 220 ILCS 5/8-505.
[76] 220 ILCS 5/9-201(c).
[77] 220 ILCS 5/4-401.
[78] We note that the Local might also have cited Section 8-101 of the Act, 220 ILCS 5/8-101, which states, in pertinent part: "[e]very public utility shall furnish, provide and maintain such service instrumentalities, equipment and facilities as shall promote the safety, health, comfort and convenience of its patrons, employees and public."

The critical question, therefore, is whether the Commission has authority, when enforcing those health and safety provisions, to touch upon matters that might also be reasonably characterized as labor-management relations matters. We conclude that we have the requisite authority. To hold otherwise would be to end the regulation of public utilities. Every act of a public utility is performed by *someone*, and in countless instances that person is managed by another *someone*. While it is certain that the Commission's power to regulate the relationship between and conduct of those persons in not unlimited, it is equally certain that we can exercise some degree of control over those relationships and conduct, in order to fulfill our unambiguous mandate to require public utilities to promote the health and safety of employees and customers. The existence of a CBA does not deprive us of that authority. Indeed, the opposite is true. The signatories to a CBA simply cannot, with any expectation of impunity, agree to do what the law prohibits[79].

Illinois precedent on this point is not recent, but that is because the applicable law is clear and settled. The General Assembly has given the Commission general authority over public utilities and – at multiple places in the Act – the specific authority to ensure the health and safety of utility employees and customers. That authority was upheld by the Illinois Supreme Court in Brotherhood of Railway Trainmen v Elgin, Joliet & Eastern Railway Co, 382 Ill. 5, 46 N.E.2d 932 (1943) (Commission order specifying the manner in which drinking water should be provided for railroad employees was permissible under the predecessor statute to Section 8-505[80] and other portions of the Act, which "expressly authorize regulations for the safety of employees" id., 382 Ill. at 69, 46 N.E.2d at 939; and the Commission's authority to enter that order was not impliedly repealed by other state law addressing employee health and safety).

Accordingly - and without deciding, at this juncture, the exact contours of the relief we can or would require - the Commission concludes that we are authorized by the Act to regulate utility staffing and repair practices that are proven to impact the health and safety of public utility employees and customers.

3. Merits of the Plan

In support of the Plan, which would obligate Peoples Gas to promote Local members into higher-level employee positions[81], the Local asserts that Peoples Gas:

> …is facing current and anticipated shortages in its most highly-skilled employee positions…due in part to a long-term failure to promote employees up the ladder to positions of higher responsibility…[Peoples Gas's] unwillingness to promote employees to "top-tier" positions (unless required to do so in order to obtain regulatory relief) has led to lengthening delays in the permanent repair of temporarily-fixed gas leaks, which may not be safe until a "permanent" repair is made. While [Peoples Gas's] field

[79] As a relevant but extreme example, management and labor could not agree to create a hazardous condition.
[80] Then, Section 57 of the Act.
[81] In particular, "Crew Leader" (top position in Peoples Gas's Distribution Department), and "Senior Service Specialist No. 1" (top position in Peoples Gas's Service Department).

> service manual urges that temporary repairs be avoided or, if used, be followed promptly by a permanent repair…lag times to complete permanent repairs are expanding, and…the use of temporary repairs is increasing. Based on experience in the field… the reason for the lengthening lag is a shortage in the ranks of those highly-skilled employees without whom permanent repairs cannot be conducted. [Peoples Gas] has no basis for challenging these assertions, as it admitted…that it has no data on the use or duration of temporary repairs.

Local Init. Br. at 3. Furthermore, the Local charges, Peoples Gas stated in these proceedings that "it plans no new initiative or program to address replenishment issues," and "customers will pay the price for such failures, whether in the form of lengthened outages, lesser quality service, or worse." Id. at 4.

Peoples Gas replies that the Plan "inappropriately would circumscribe and invade the role of management." PGL-NS Init. Br. at 228. The result, PGL charges, would be "less flexibility" for Peoples Gas management and "possible disputes." Id. at 230. As for the Local's willingness to subordinate hiring to technological obsolescence and infrastructure improvements, Peoples Gas avers that the Local "did not provide specifics." Id. at 228. In fact, Peoples Gas suggests, the Plan would undermine, rather than promote, the efficiency favored by the legislature in Section 1-102 of the PUA[82]. As Peoples Gas puts it, the very situation criticized by the Local - "doing more with fewer people" – "sounds like efficiency." PGL-NS Rep. Br. at 177. Finally, Peoples Gas characterizes the Local's evidence as anecdotal and inadequate to demonstrate systemic or chronic problems affecting safety. Id. at 178.

4. Commission Conclusion re: Merits of the Plan

The Commission finds that the Local has raised serious questions regarding the impact of Peoples Gas's staffing and repair practices on employee and public safety. The Local alleges that Peoples Gas "encourages the frequent use of temporary repairs," that temporary repairs are used "routinely and extensively," that the interval between temporary and permanent repairs is "growing significantly," and that such practices contravene Peoples Gas's Field Service Manual, compromise public safety and are attributable to insufficient staffing among the top-tier employees that must complete permanent repairs. The gravity of the circumstances alleged by the Local is only heightened by the presence of the Local's membership on the "front line," where the potential for harm to life, health and property is evaluated first-hand. We have no doubts about the credibility or the sincerity of the Local's presentation in these proceedings.

Nonetheless, the Commission is not ready to conclude, based on the Local's ground-level view, that Peoples Gas's staffing and repair practices do jeopardize, beyond an unavoidable margin of error, either the safety of workers and customers or service reliability. While the Local's description of the response to serious (Class I) gas leaks at a Chicago hospital is unquestionably troubling, it remains, as Peoples Gas

[82] 220 ILCS 5/1-102.

avers, a single example of the systemic deficiencies the Local describes, which, we recognize, is all the Local intended it to be. Additionally, Peoples Gas's decision to hire eight outside contractors to perform seasonal and, even from the Local's standpoint, routine tasks is not necessarily indicative of inadequate staffing or unsafe or unreliable conditions. PGL-NS Rep. Br. at 178. In order to immediately implement the Local's proposed staffing Plan, the Commission would need precise aggregate data regarding the practices reported by the Local, confirming that health and safety are compromised and that the Plan is likely to provide a remedy. Consequently, on the record provided here, the Commission will not require implementation of the Local's staffing plan.

The Local's audit recommendation is another story, however. Our hesitation to impose the Local's Plan is not based on evidence disproving its efficacy, but, rather, the absence of systemic statistical evidence that would have persuaded us to adopt the Plan or something similar today. Instead of furnishing meaningful record evidence to reassure the Commission and the public that safety and reliability are not at risk due to staffing deficiencies, Peoples Gas trivialized the efforts of its own employees to call attention to important concerns. The Commission addresses the proposed audit in the next section of this Order.

B. Audit of Repairs and Staffing

1. Parties' Positions and Applicable Law

As noted above, the Local requests an independent audit of: (a) work order response times and backlogs (inclusive of temporary repairs) at Peoples Gas; and (b) staffing levels among the workforce that handles those repairs. The Local and Peoples Gas concur that express authority to require an audit resides in Section 8-102 of the Act[83], which states:

> The Commission is authorized to conduct or order a management audit or investigation of any public utility or part thereof. The audit or investigation may examine the reasonableness, prudence, or efficiency of any aspect of the utility's operations, costs, management decisions or functions that may affect the adequacy, safety, efficiency or reliability of utility service….

The parties disagree, however, about whether the necessary findings for a Section 8-102 are supported by the evidentiary record here. Section 8-102 authorizes an audit by the Commission "only when it has reasonable grounds to believe that the audit or investigation is necessary to assure that the utility is providing adequate, efficient, reliable and safe least-cost service."

As proof that "reasonable grounds" for an audit or investigation are absent, Peoples Gas states that it has already "established a compliance monitoring group that

[83] 220 ILCS 5/8-102. The Commission also has the general power to "inquire into the management" of a public utility to "keep itself informed as to the manner and method in which the business is conducted…and the manner in which the[] plants, equipment and other property…are managed, conducted and operated." 220 ILCS 5/4-101. Similarly, a utility "shall furnish" to us "all information required by it to effect the provisions of this Act, and shall make specific answers to all questions submitted by the Commission." 220 ILCS 5/5-101.

audits compliance with [Peoples Gas's] Field Service Manual." PGL-NS Rep. Br. at 179. But other than the bare oral declaration during cross-examination that such a monitoring group is now "performing audits," (Tr. 228 (Doerk)) Peoples Gas provides no information. Thus, Peoples Gas does not indicate whether the group scrutinizes the work order backlogs, completion times and repair staffing the Local addresses. Peoples Gas also testifies that it is already "working with a Commission hired consultant reviewing all [Peoples Gas's] pipeline safety related activities." PGL-NS Ex. 2.0 at 6. But, again, Peoples Gas offers nothing more, and the Commission cannot – in view of the Local's detailed evidence andPeoples Gas's silence - fulfill its obligations regarding customer and employee safety by simply assuming that a pipeline consultant is reviewing, for example, leak repairs inside or adjacent to customer premises.

2. Commission Conclusion

Importantly, Peoples Gas acknowledges that it has not compiled information concerning the "use, frequency and average duration of temporary repairs." Tr. 223 (Doerk). Consequently, the record provides no statistical information to either justify the Local's One-for-One proposal or to dismiss the Local's audit request. Therefore, the inferences suggested by the direct observations and anecdotes of Local members - that permanent repairs are not performed soon enough because qualified employees are busy with other work, and that public and employee safety are therefore compromised – are not rebutted. Moreover, there is history ofPeoples Gas's safety-related deficiencies in the record. Peoples Gas confirms that it was fined for failure to conduct required inside safety inspections during the period from 2000 through 2004. Id. 247-48. The Commission concludes that there is reasonable ground to require an appropriately tailored audit of certain aspects of Peoples Gas's operations[84].

So that the audit results are useful to interested parties, and so that Peoples Gas has clear directions, the Commission will sharpen the focus of the Local's audit request ("work order response times and backlogs (inclusive of temporary repairs)"). The safety concerns raised by the Local's testimony, taken as a whole, are associated with the frequency of temporary repairs and the time interval between temporary and permanent repairs[85]. Consequently, the audit should quantify, for each of the calendar years 2003 through 2007, the total number of gas leaks repaired by Peoples Gas, and the total number and percentage of those in which temporary repairs were used. Separate data should be presented for each class of gas leak (i.e., Classes I through III). The audit should also quantify the percentage of all gas leaks repaired and number of temporarily repaired gas leaks for which permanent repairs were completed in one, two, three, four,

[84] On exceptions, PGL asserts that the stated ground for the audit required here is "one particular leak [at a Chicago hospital]." PGL-NS BOE at 85. That is patently incorrect. The Local testified to *patterns and practices observed and performed by its membership* while in PGL's employ, which were fully described throughout Section XII of this Order and are the basis for our audit directive.

[85] *E.g.*, "Our experience is that temporary repairs are used routinely and extensively throughout [PGL's] service territory, and that the period of time between when a temporary repair is implemented and a permanent repair is completed is growing significantly. This is not a tolerable state-of-affairs because gas leaks that are not fully repaired do not get better on their own, they can only get worse. In my experience and those of other Local 18007 employees, the Company does encourage the frequent use of temporary repairs as a stopgap measure to respond to work orders quickly." Local Ex. 2.0 at 13.

five, and more than five business days. Again, separate data should be presented for each class of gas leak[86].

With respect to staffing, the Local's audit request ("staffing levels among the utility workforce at PGL") also needs narrowing. The Local's testimony, taken as a whole, associates safety issues with insufficient staffing of "top-tier" positions among Peoples Gas's work force, particularly Senior Service Specialist No. 1 in the Service Department and Crew Leader in the Distribution Department[87]. Therefore, the audit should quantify, for each of the calendar years 2003 through 2007, the total number and percentage of gas leaks repaired by Peoples Gas in which a CL or SSS-1 participated, the total number and percentage of those in which temporary repairs were used, and the total number of such gas leaks assigned per CL and SSS-1 during each month. Separate data should be presented for each class of gas leak (i.e., Classes I through III).

Peoples Gas and the Local are the entities most familiar with the pertinent subject matter. Accordingly, the Commission encourages them to expand or reorganize - by mutual agreement - the focus of the audit to make its results as useful as is practicable. Any such expansions or revisions should be explained in the final report to the Commission. We also direct that the Natural Gas Pipeline Safety Section of our Staff respond affirmatively (within the limits of its resources) to any reasonable request from Peoples Gas and the Local for assistance in shaping and conducting the audit.

The audit shall be completed and its results submitted to the Commission's Staff within the 180 days after the entry of this Order, unless Peoples Gas and the Local mutually agree to a different submission deadline. Contemporaneous with such submission, Peoples Gas shall provide a copy of the audit results to the Local, subject to execution by the Local of a reasonable confidentiality pledge, if such pledge is requested byPeoples Gas. The audit results shall be attested to by the auditing party.

Although the Local requests an independent audit, the Commission sees no reason why Peoples Gas personnel should be precluded from performing the audit and attesting to their results. Regarding costs, the audit described above is not materially different from responding to discovery requests in proceedings like these. Peoples Gas should bear such costs and include them in its expense calculations in a subsequent rate case. If Peoples Gas, at its discretion, instead elects to hire an independent auditor, Section 8-102 states that "the cost of an independent audit shall be borne

[86] Peoples Gas curiously complains that the Commission is requiring "the reporting of specific statistics which were never addressed in the evidentiary record." PGL-NS BOE at 87. That is precisely the point. The Local provided troubling evidence of practices imperiling public health and safety and PGL provided no responsive evidence. Our authority to require data under such circumstances is extensively cited in this Order.

[87] *E.g.*, the Local "testified that lag times to complete permanent repairs are expanding, and that the use of temporary repairs is increasing. Based on experience in the field, the [Local] asserts that the reason for the lengthening lag is a shortage in the ranks of those highly-skilled employees without whom permanent repairs cannot be conducted." Local Init. Br. at 3.

initially by the utility, but shall be recovered as an expense through normal ratemaking procedures." By its terms, this is a mandatory cost allocation and recovery scheme and the Commission must implement it in this instance.

The Local also requests a commitment to expeditious action after the audit is completed. Local BOE at 18. We believe that is premature. We do not want to prejudge the results of the audit or rule out the prospect that the parties will craft their own remediation plan if the audit demonstrates that one is warranted. Instead, we will leave it to the Local, or Staff, or some other affected stakeholder, to request or initiate a new proceeding under the authority of the Act (much of it discussed above) based on the audit results. Insofar as public health and safety concerns are implicated, such proceeding could be conducted on an expedited basis.

XII. FINDINGS AND ORDERING PARAGRAPHS

The Commission, having considered the entire record herein and being fully advised in the premises, is of the opinion and finds that:

(1) Peoples Gas is an Illinois corporation engaged in the transportation, purchase, storage, distribution and sale of natural gas to the public in Illinois and is a public utility as defined in Section 3-105 of the Public Utilities Act;

(2) North Shore is an Illinois corporation engaged in the transportation, purchase, storage, distribution and sale of natural gas to the public in Illinois and is a public utility as defined in Section 3-105 of the Public Utilities Act;

(3) the Commission has jurisdiction over the parties and the subject matter herein;

(4) the recitals of fact and conclusions of law reached in the prefatory portion of this Order are supported by the evidence of record, and are hereby adopted as findings of fact and conclusions of law; the Appendix attached hereto provides supporting calculations;

(5) the test year for the determination of the rates herein found to be just and reasonable should be the 12 months ending September 30, 2006; such test year is appropriate for purposes of this proceeding;

(6) the $2,327,999,000 original cost for Peoples Gas and the $369,442,000 original cost for North Shore of plant at September 30, 2006, as reflected on the Companies' Schedules B-1, Line 1, column D, are unconditionally approved as the original cost of plant

(7) for the test year ending September 30, 2006, and for the purposes of this proceeding, Peoples Gas' original cost rate base with adjustments is $1,212,274.000;

(8) for the test year ending September 30, 2006, and for the purposes of this proceeding, North Shore's original cost rate base with adjustments is $182,033,000;

(9) a just and reasonable return which Peoples Gas should be allowed to earn on its net original cost rate base is 7.76%; this rate of return incorporates a return on common equity of 10.19% and costs of long-term debt of 4.67, with a just and reasonable capital structure of 56% common equity and 44% long-term debt;

(10) a just and reasonable return which North Shore should be allowed to earn on its net original cost rate base is 7.96%; this rate of return incorporates a return on common equity of 9.99% and costs of long-term debt of 5.39%, with a just and reasonable capital structure of 56% common equity and 44% long-term debt;

(11) Peoples Gas' rate of return set forth in Finding (9) results in approved base rate net operating income of $ $94,073,000;

(12) North Shore's rate of return set forth in Finding (10) results in approved base rate net operating income of $14,489,000 ;

(13) Peoples Gas' rates, which are presently in effect, are insufficient to generate the operating income necessary to permit Peoples Gas the opportunity to earn a fair and reasonable return on net original cost rate base; these rates should be permanently canceled and annulled;

(14) North Shore's rates, which are presently in effect, are insufficient to generate the operating income necessary to permit North Shore the opportunity to earn a fair and reasonable return on net original cost rate base; these rates should be permanently canceled and annulled;

(15) the specific rates proposed by Peoples Gas in its initial filing do not reflect various determinations made in this Order regarding revenue requirement, cost of service allocations, and rate design; Peoples Gas' proposed rates should be permanently canceled and annulled consistent with the findings herein;

(16) the specific rates proposed by North Shore in its initial filing do not reflect various determinations made in this Order regarding revenue requirement, cost of service allocations, and rate design; North Shore's proposed rates should be permanently canceled and annulled consistent with the findings herein;

(17) Peoples Gas should be authorized to place into effect tariff sheets designed to produce annual revenues of $461,780,000 , including base rate and rider revenues, which represents a gross increase of $71,191,000 ; such revenues will provide Peoples Gas with an opportunity to earn the rate of return set forth in Finding (9) above; based on the record in this proceeding, this return is just and reasonable;

(18) North Shore should be authorized to place into effect tariff sheets designed to produce annual base rate revenues of $63,439,000 , including base rate and rider revenues, which represent a gross decrease of $213,000 ; such revenues will provide North Shore with an opportunity to earn the rate of return set forth in Finding (10) above; based on the record in this proceeding, this return is just and reasonable;

(19) the determinations regarding cost of service and rate design contained in the prefatory portion of this Order are reasonable for purposes of this proceeding; the tariffs filed by North Shore and Peoples Gas should incorporate the rates and rate design set forth and referred to herein;

(20) new tariff sheets authorized to be filed by this Order should reflect an effective date not less than three (3) days after the date of filing, with the tariff sheets to be corrected, if necessary, within that time period;

(21) Peoples Gas and North Shore should file a tariff sheet enabling transportation customers to return to their required baseload volume after a delivery reduction, even while a delivery restriction continues, as described in Section X.C.7 (b) of this Order

(22) the Utilities should perform an avoided cost study (or, at the Utilities' discretion, an embedded cost study) as described in subsection X.B.3. of this Order, which should be completed within 120 days of the date of this Order, and Rider SBO shall be revised in accordance with the results of that study;

(23) as required in subsection X.D.2(b) above, the Utilities should have customer consent processes in place and operational no less than 45 days after the date of this Order;

(24) all enhancements for the PegasysTM electronic bulletin board for North Shore and Peoples Gas, as addressed in the record in these proceedings, should be complete, fully operational and available for use by customers on or before August 15, 2008;

(25) Peoples Gas should conduct an audit of gas leaks and repairs in conformance with the Commission's directives in Section XI. B. of this Order, with the costs of the audit borne in the manner described in that section;

(26) Peoples Gas should, no later than 120 days from the date of this Final Order, submit to the Director of the Energy Division a report of procedures documenting how it allocates Manlove storage capacity and, how it ensures no harm to ratepayers from its allocation decisions, as is directed under Part V of this Order;

(27) the Utilities should include in the Rider VBA schedule the recommended language changes proposed by Staff and accepted by the Utilities, and as directed in Part IV and Part VII of this Order;

(28) upon conclusion of the Rider VBA pilot program, if the Utilities wish to make Rider VBA permanent, they shall file a general rate case;

(29) Staff should provide the Commission with an annual report on Rider VBA's effect on the Rate of Return, as directed in Part IV C. and Part VII A.; and

(30) the Utilities' Rider EEP should include an annual reconciliation procedure, provision for an internal audit, and a change to the monthly tariff date as Staff has proposed.

IT IS THEREFORE ORDERED by the Illinois Commerce Commission that the tariff sheets presently in effect rendered by The Peoples Gas Light and Coke Company and North Shore Gas Company are hereby permanently canceled and annulled, effective at such time as the new tariff sheets approved herein become effective by virtue of this Order.

IT IS FURTHER ORDERED that the proposed tariffs seeking a general rate increase, filed by The Peoples Gas Light and Coke Company and North Shore Gas Company on March 9, 2007 are permanently canceled and annulled.

IT IS FURTHER ORDERED that The Peoples Gas Light and Coke Company and North Shore Gas Company are authorized to file new tariff sheets with supporting workpapers in accordance with Findings 17 and 18 of this Order, applicable to service furnished on and after the effective date of said tariff sheets.

IT IS FURTHER ORDERED that The Peoples Gas Light and Coke Company and North Shore Gas Company shall file a tariff sheet enabling transportation customers to return to their required baseload volume after a delivery reduction, even while a delivery restriction continues, as described in Section X.C.7.(b) of this Order.

IT IS FURTHER ORDERED THAT the Utilities shall perform an avoided cost study (or, at the Utilities' discretion, an embedded cost study) as described in subsection X.B.3 of this Order, which should be completed within 120 days of the date of this Order, and Rider SBO shall be revised in accordance with the results of that study.

IT IS FURTHER ORDERED THAT, as required in subsection X.D.2(b) above, the Utilities shall have customer consent processes in place and operational no less than 45 days after the date of this Order.

IT IS FURTHER ORDERED that all enhancements for the PegasysTM electronic bulletin board for North Shore Gas Company and The Peoples Gas Light and Coke Company, as addressed in the record in these proceedings, should be complete, fully operational and available for use by customers on or before August 15, 2008.

IT IS FURTHER ORDERED that The Peoples Gas Light and Coke Company shall conduct an audit of gas leaks and repairs in conformance with the Commission's directives in Section XI.B. of this Order, with the costs of the audit borne in the manner described in that section.

IT IS FURTHER ORDERED that no later than 120 days from the date of this Final Order, Peoples Gas shall submit to the Director of the Energy Division a report of procedures documenting how it allocates Manlove storage capacity and, how it ensures no harm to ratepayers from its allocation decisions.

IT IS FURTHER ORDERED that the recommended language changes proposed by Staff and accepted by the Utilities, as well as other changes articulated in Section VII(A)(1), shall be included in the Rider VBA schedule.

IT IS FURTHER ORDERED that, upon conclusion of the Rider VBA pilot program, if the Utilities wish to make Rider VBA permanent, they shall file a general rate case.

IT IS FURTHER ORDERED that the Utilities' Rider EEP shall include an annual reconciliation procedure, provision for an internal audit, and a change to the monthly tariff date as Staff has proposed.

IT IS FURTHER ORDERED that any motions, petitions, objections, and other matters in this proceeding which remain unresolved are disposed of consistent with the conclusions herein.

IT IS FURTHER ORDERED that, subject to the provisions of Section 10-113 of the Public Utilities Act and 83 Ill. Adm. Code 200.880, this Order is final; it is not subject to the Administrative Review Law.

By order of the Commission this 5th day of February, 2008.

(SIGNED) CHARLES E. BOX

Chairman

ATTACHMENT K

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274 P.U.R.4th 257Re Central Hudson Gas & Electric Corporation
Cases 08-E-0887, 08-G-0888, and 09-M-0004

New York Public Service Commission
June 22, 2009

ORDER authorizing an energy utility to increase its delivery rates by $38.0 million for electric service and by $13.6 million for gas service, reflecting an authorized rate of return on equity (ROE) of 10.0% and an overall rate of return of 7.28%. Commission employs an ROE methodology that gives the results of a two-state discounted cash flow model twice the weight of the results of the capital asset pricing methodologies. The authorized ROE incorporates: (i) a downward 48 basis point credit quality adjustment to reflect the fact that the utility faces lower financial **risk** than the proxy group used in determining ROE; and (ii) a downward 10 basis point adjustment to reflect reduced **risk** resulting from the adoption of revenue **decoupling** mechanisms.

Economic Considerations. Commission considers macroeconomic conditions in determining the rate increase, finding that it would be remiss in its obligation to the public interest if it were to fail to take notice of the magnitude and depth of the current recession. Moreover, it finds that macroeconomic considerations may be used as the basis for requiring austerity adjustments to revenue requirement. Commission adopts an approach to austerity that does not single out a disallowance for any particular expense. Instead, it imputes an austerity adjustment to revenue requirement and leaves the utility free to choose its own strategy for achieving short-term expense adjustments.

Commission makes clear that an austerity adjustment does not directly translate into an immediate and negative impact on rate of return. It explains that to the extent the utility defers or forgoes expenses in response to an austerity adjustment, there would be no effect on earned rate of return on equity during the rate year.

The rate increases incorporate austerity savings of $2.4 million for electric and $600,000 for gas service. The utility must exercise its best efforts to achieve the austerity savings by effectively managing its resources. However, recognizing that the utility may not realize the full amount of the austerity savings incorporated in rates, the commission authorizes the utility to petition at the end of the rate year for a deferral corresponding to that amount of austerity-related expense reductions which, despite its best efforts, has not been realized.

Electric Bill Credit. In order to mitigate the bill impact of the rate increase for electric delivery service, the commission institutes an electric bill credit (EBC). Commission finds that phasing in the EBC, which results from a netting of certain deferred debits and credit, over three years will provide the greatest benefit to ratepayers during the current economic downturn, while moderating the impact of the credit's eventual expiration. The EBC will offset $20 million of the electric delivery rate increase during the rate year ending June 30, 2010, $10 million in the year ending June 30, 2011, and $6 million in the year ending June 30, 2012. However, the amounts specified for the years ending in 2011 and 2012 are subject to modification upon a showing of good cause.

Purchased Power Agreement Benefits. Commission approves a revision to the method used to allocate the net benefits realized by the utility from its below-market power purchase contract with the owners of the Nine Mile Point Unit No. 2 power plant (NMP2). Previously, the benefits were flowed-through the electric costs adjustment mechanism and allocated among service classes and sub-classes entirely on the basis of kWh sales. As revised, 69% of the benefits will be allocated based on energy and the remaining 31% will be allocated based on peak demand. Noting that the PPA benefits resulted from the utility's sale of NMP2, the commission finds that the revised allocation method creates a better match between past capital cost responsibility and the receipt of the benefits now flowing from

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NMP2.

Revenue Decoupling. Commission accepts a $4 million dollar reconciliation circuit breaker for the electric revenue **decoupling** mechanism (RDM) and a $2 million circuit breaker for the gas RDM. It finds that the application of a weather normalization clause and the availability of the circuit breakers should prevent excessive amounts from accumulating either for credit or surcharge, thus rendering immaterial any **risk** to the economic value of sums owned to the utility through operation of the RDMs.

P.U.R. Headnote and Classification

1.
RATES

s49
NY.D.P.S. 2009
[N.Y.] Factors affecting reasonableness - Macroeconomic conditions - Recessionary economy - Austerity adjustment to revenue requirement - Electric and gas rate proceeding.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

2.
RATES

s2
NY.D.P.S. 2009
[N.Y.] Jurisdiction and powers - State commission - Power to consider macroeconomic conditions - In determining reasonableness of utility rates.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

3.
EXPENSES

s0
NY.D.P.S. 2009
[N.Y.] Ascertainment - Abnormal macroeconomic conditions - Recessionary economy - Austerity adjustment to revenue requirement - Electric and gas rate proceeding.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

4.
EXPENSES

s5
NY.D.P.S. 2009
[N.Y.] Factors affecting reasonableness - Macroeconomic conditions - Recessionary economy - Austerity adjustment to revenue requirement - Electric and gas rate proceeding.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

5.
RETURN

s5
NY.D.P.S. 2009
[N.Y.] Reasonableness - Macroeconomic conditions - Recessionary economy - Austerity adjustment to revenue requirement - No immediate effect on earned rate of return on equity.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

6.
REVENUES

s
NY.D.P.S. 2009
[N.Y.] Sales forecasts - Weather normalization - Heating and cooling degree day inputs - Use of 10-year average - Electric and gas rate case.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

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7.
REVENUES

s
NY.D.P.S. 2009
[N.Y.] Forecasts - Finance charge revenue - Method of calculation - Electric and gas rate case.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

8.
REVENUES

s
NY.D.P.S. 2009
[N.Y.] Sales forecasts - Update for macroeconomic conditions and projected sales reductions - Electric and gas rate case.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

9.
EXPENSES

s2
NY.D.P.S. 2009
[N.Y.] Directors and officers liability insurance - 50/50 sharing of cost responsibility - Grounds - Benefits to both ratepayers and shareholders - Electric and gas utility.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

10.
EXPENSES

s5
NY.D.P.S. 2009
[N.Y.] Salaries and wages - Update to reflect most recent employee count - Opportunities for austerity savings - Electric and gas utility.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

11.
EXPENSES

s05
NY.D.P.S. 2009
[N.Y.] Incentive compensation plans - Grounds for disallowance - No showing of benefit to ratepayers commensurate with cost - Electric and gas utility.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

12.
EXPENSES

s5
NY.D.P.S. 2009
[N.Y.] Salaries and wages - Updated figures - Use of original historic test year as starting point - Electric and gas utility.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

13.
EXPENSES

s0
NY.D.P.S. 2009
[N.Y.] Environmental investigation and remediation - Manufactured gas plan site cleanup - Allowance based on three-year historical average - Balance sheet offset of any excess costs actually incurred during rate year - Electric and gas utility.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

14.
EXPENSES

s9

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NY.D.P.S. 2009
[N.Y.] Regulatory commission expense - Method of recovery - Electric and gas utility.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

15.
COMMISSIONS

s8
NY.D.P.S. 2009
[N.Y.] Expenses and compensation - Assessments against utilities - Method of recovery.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

16.
EXPENSES

s0
NY.D.P.S. 2009
[N.Y.] Storm restoration - Three-year average excluding anomalous ice storm - Deferral of costs of excluded storm - Electric and gas utility.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

17.
EXPENSES

s
NY.D.P.S. 2009
[N.Y.] Ascertainment - Costs without expense history - Deferral accounting.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

18.
EXPENSES

s20
NY.D.P.S. 2009
[N.Y.] Electric utility - Stray voltage testing - Compliance with expanded requirements - Uncertain costs - Continued deferral accounting pending establishment of expense history.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

19.
EXPENSES

s21
NY.D.P.S. 2009
[N.Y.] Electric utility - Transmission sag mitigation program - Funding from available net credits - Cap on total charge against credits.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

20.
EXPENSES

s18
NY.D.P.S. 2009
[N.Y.] Uncollectibles - Allowance based on recent experience - Denial of automatic deferral authority - Electric and gas utility.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

21.
EXPENSES

s09
NY.D.P.S. 2009
[N.Y.] Property taxes - Updated allowance based on latest available information - Denial of request for bilateral reconciliation - Electric and gas utility.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

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22.
EXPENSES

s09
NY.D.P.S. 2009
[N.Y.] Property taxes - Treatment of tax litigation costs - Reimbursement from proceeds of successful tax challenges - Sharing of balance of proceeds with ratepayers - Opportunity to propose different approach - Electric and gas utility.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

23.
EXPENSES

s3
NY.D.P.S. 2009
[N.Y.] Legal expense - Tax litigation costs - Reimbursement from proceeds of successful tax challenges - Sharing of balance of proceeds with ratepayers - Opportunity to propose different approach - Electric and gas utility.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

24.
EXPENSES

s14
NY.D.P.S. 2009
[N.Y.] Income taxes - Adjustment for avoided cost interest capitalized - Electric and gas utility.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

25.
VALUATION

s80
NY.D.P.S. 2009
[N.Y.] Electric rate base - Capital expenditures - Protection of ratepayers from over or under expenditures - Target and deferral mechanisms - One-way downward true-up of over and under expenditures.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

26.
VALUATION

s81
NY.D.P.S. 2009
[N.Y.] Natural gas rate base - Capital expenditures - Protection of ratepayers from over or under expenditures - Target and deferral mechanisms - One-way downward true-up of over and under expenditures.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

27.
VALUATION

s23
NY.D.P.S. 2009
[N.Y.] Incomplete project - Removal from rate base - Accrual of carrying charges at pre-tax rate of return based on actual project costs - Deferral authorization conditioned on project being placed in service during rate year - Electric utility.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

28.
VALUATION

s80
NY.D.P.S. 2009
[N.Y.] Electric rate base - Incomplete project - Transmission sag mitigation program - Deferral of capital component subject to true-up upon completion.

Re Central Hudson Gas & Electric Corporation

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P.U.R. Headnote and Classification

29.
VALUATION

s23
NY.D.P.S. 2009
[N.Y.] Incomplete project - Transmission sag mitigation program - Deferral of capital component subject to true-up upon completion - Electric utility.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

30.
VALUATION

s80
NY.D.P.S. 2009
[N.Y.] Electric rate base - Earnings base/capitalization adjustment - Drivers of change in adjustment from case to case - Information requirements.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

31.
VALUATION

s81
NY.D.P.S. 2009
[N.Y.] Natural gas rate base - Earnings base/capitalization adjustment - Drivers of change in adjustment from case to case - Information requirements.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

32.
DEPRECIATION

s5
NY.D.P.S. 2009
[N.Y.] Gas plant - Long-lived distribution mains and services - Negative net salvage associated with retirements - Current expensing of excess negative net salvage.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

33.
DEPRECIATION

s1
NY.D.P.S. 2009
[N.Y.] Life of property and salvage - Methods and theories - Current expensing of excess negative net salvage - Natural gas utility.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

34.
DEPRECIATION

s0
NY.D.P.S. 2009
[N.Y.] Electric plant - Service lives and retirement curves - Allowance for net salvage.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

35.
DEPRECIATION

s1
NY.D.P.S. 2009
[N.Y.] Life of property and salvage - Service lives and retirement curves - Allowance for net salvage - Electric utility.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

36.
DEPRECIATION

s7

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NY.D.P.S. 2009
[N.Y.] Electric and gas utility - Common plant - Service lives - Amortization periods.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

37.
DEPRECIATION

s1
NY.D.P.S. 2009
[N.Y.] Life of property - Service lives - Amortization periods - Common plant - Electric and gas utility.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

38.
RATES

s21
NY.D.P.S. 2009
[N.Y.] Electric utility - Offset to delivery rate increase - Mitigation of bill shock - Bill credit resulting from netting of deferred debits and credits - Allocation to customer classes - Phase-in.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

39.
EXPENSES

s20
NY.D.P.S. 2009
[N.Y.] Electric utility - Offset to delivery rate increase - Mitigation of bill shock - Bill credit resulting from netting of deferred debits and credits - Allocation to customer classes - Phase-in.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

40.
RETURN

s6.1
NY.D.P.S. 2009
[N.Y.] Reasonableness - Capital structure - Equity ratio - Exclusion of capital infusion from parent - Electric and gas utility.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

41.
RETURN

s6.4
NY.D.P.S. 2009
[N.Y.] Reasonableness - Cost of equity - Credit quality adjustment - Electric and gas utility.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

42.
RETURN

s4
NY.D.P.S. 2009
[N.Y.] Reasonableness - Factors considered - Financial risk - Credit quality adjustment to cost of equity - Electric and gas utility.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

43.
RETURN

s6.4
NY.D.P.S. 2009
[N.Y.] Reasonableness - Cost of equity - Adjustment for reduced **risk** resulting from revenue **decoupling** mechanisms - Electric and gas utility.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

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44.
RETURN

s4
NY.D.P.S. 2009
[N.Y.] Reasonableness - Factors considered - **Risk** - Adjustment for reduced **risk** resulting from revenue **decoupling** mechanisms - Electric and gas utility.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

45.
RETURN

s6.4
NY.D.P.S. 2009
[N.Y.] Reasonableness - Cost of equity - Estimation methodology - Discounted cash flow model - Capital asset pricing model - Relative weights - Electric and gas utility.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

46.
RETURN

s6.4
NY.D.P.S. 2009
[N.Y.] Reasonableness - Cost of equity - Denial of issuance expense adjustment - Electric and gas utility.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

47.
RETURN

s6.2
NY.D.P.S. 2009
[N.Y.] Reasonableness - Cost of debt - Auction rate debt - New long-term debt issuances - True-up and deferral - Electric and gas utility.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

48.
RETURN

s6.3
NY.D.P.S. 2009
[N.Y.] Reasonableness - Cost of preferred stock - Electric and gas utility.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

49.
RETURN

s3
NY.D.P.S. 2009
[N.Y.] Electric and gas utility - Overall rate of return - Reasonableness.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

50.
RETURN

s7
NY.D.P.S. 2009
[N.Y.] Electric utility - Overall rate of return - Reasonableness.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

51.
RETURN

s2
NY.D.P.S. 2009
[N.Y.] Gas utility - Overall rate of return - Reasonableness.

Re Central Hudson Gas & Electric Corporation

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P.U.R. Headnote and Classification

52.
RATES

s43
NY.D.P.S. 2009
[N.Y.] Reasonableness - Cost of service - Allocation of cost responsibility - Electric and gas utility.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

53.
APPORTIONMENT

s3
NY.D.P.S. 2009
[N.Y.] Allocation of common costs - Appropriate allocation ratio - Need for objective analysis - Electric and gas utility.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

54.
APPORTIONMENT

s1
NY.D.P.S. 2009
[N.Y.] Gas distribution mains - Allocation methodology - 65% demand/35% customer allocation - Local distribution company.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

55.
APPORTIONMENT

s8
NY.D.P.S. 2009
[N.Y.] Natural gas - Distribution mains - Classification and allocation - 65% demand/35% customer allocation - Local distribution company.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

56.
RATES

s73
NY.D.P.S. 2009
[N.Y.] Natural gas - Matching cost responsibility with cost causation - Allocation of costs of distribution mains - 65% demand/35% customer allocation - Local distribution company.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

57.
APPORTIONMENT

s3
NY.D.P.S. 2009
[N.Y.] Electric utility - Allocation of procurement costs - Methodology.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

58.
RATES

s21
NY.D.P.S. 2009
[N.Y.] Electric utility - Allocation of procurement costs - Methodology.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

59.
RATES

s21
NY.D.P.S. 2009
[N.Y.] Electric utility - Cost of service - Need for delivery-only historic, embedded cost study.

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Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

60.
RATES

s73
NY.D.P.S. 2009
[N.Y.] Natural gas - Cost of service - Need for marginal cost study.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

61.
APPORTIONMENT

s8
NY.D.P.S. 2009
[N.Y.] Natural gas - Regulator stations - Cost classification and allocation - Usage based allocation - Local distribution company.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

62.
APPORTIONMENT

s9
NY.D.P.S. 2009
[N.Y.] Cost of meters - Classification and allocation - Usage based allocation - Natural gas local distribution company.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

63.
RATES

s51
NY.D.P.S. 2009
[N.Y.] Reasonableness - Avoiding rate shock - Allocation constraint - 1.25 times system average increase.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

64.
RATES

s21
NY.D.P.S. 2009
[N.Y.] Electric utility - Allocation of increase to customer classes - Avoiding rate shock - Allocation constraint - 1.25 times system average increase.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

65.
RATES

s73
NY.D.P.S. 2009
[N.Y.] Natural gas - Allocation of increase to customer classes - Avoiding rate shock - Allocation constraint - 120% of system average increase.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

66.
RATES

s36
NY.D.P.S. 2009
[N.Y.] Electric rate design - Customer charges - Residential customers - Movement toward cost of service - As constrained by gradualism.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

67.
RATES

s78
NY.D.P.S. 2009
[N.Y.] Natural gas rate design - Customer charges -

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Residential customers - Movement toward cost of service - As constrained by gradualism.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

68.
RATES

s84
NY.D.P.S. 2009
[N.Y.] Natural gas rate design - Firm transportation service - Billing based on maximum daily quantity.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

69.
RATES

s80
NY.D.P.S. 2009
[N.Y.] Natural gas rate design - Special factors - Retail access lost revenue - Recovery mechanism - 50/50 split between merchant function avoided by retail access customers and transition charge paid by all customers.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

70.
MONOPOLY AND COMPETITION

s8
NY.D.P.S. 2009
[N.Y.] Retail access - Lost revenue recovery mechanism - 50/50 split between merchant function avoided by retail access customers and transition charge paid by all customers - Local distribution company.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

71.
RATES

s32
NY.D.P.S. 2009
[N.Y.] Electric rate design - Special charges - Retail access lost revenue recovery mechanism - Allocation of cost responsibility.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

72.
MONOPOLY AND COMPETITION

s4
NY.D.P.S. 2009
[N.Y.] Electric utility - Retail access lost revenue recovery mechanism - Allocation of cost responsibility.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

73.
RATES

s30
NY.D.P.S. 2009
[N.Y.] Electric rate design - Voltage factor - Implementation date.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

74.
RATES

s80
NY.D.P.S. 2009
[N.Y.] Natural gas rate design - Special factors - Lost and unaccounted for gas targets.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

75.
AUTOMATIC ADJUSTMENT CLAUSES

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s3
NY.D.P.S. 2009
[N.Y.] Electric cost adjustment mechanism - Purchased power agreement benefits - From below-market contract with Nine Mile Point Unit 2 - Flow-through to service classes and sub-classes - 69% energy/31% demand allocation.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

76.
AUTOMATIC ADJUSTMENT CLAUSES

s8
NY.D.P.S. 2009
[N.Y.] Electric cost adjustment mechanism - Purchased power agreement benefits - From below-market contract with Nine Mile Point Unit 2 - Flow-through to service classes and sub-classes - 69% energy/31% demand allocation.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

77.
SERVICE

s20
NY.D.P.S. 2009
[N.Y.] Electric utility - Safety and reliability performance mechanisms - Effect of failure to meet targets.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

78.
RATES

s32
NY.D.P.S. 2009
[N.Y.] Electric rate design - Electric reliability performance mechanism - Project specific targets - Compliance reports - Effect of failure to meet targets.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

79.
RATES

s32
NY.D.P.S. 2009
[N.Y.] Electric rate design - Service quality performance mechanism - Performance targets - Effect of failure to meet targets.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

80.
SERVICE

s32
NY.D.P.S. 2009
[N.Y.] Natural gas - Gas safety performance mechanism - Effect of failure to meet performance targets - Size of potential negative revenue adjustments - Local distribution company.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

81.
RATES

s83
NY.D.P.S. 2009
[N.Y.] Natural gas rate design - Safety performance mechanism - Effect of failure to meet performance targets - Size of potential negative revenue adjustments - Local distribution company.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

82.
SERVICE

s32

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NY.D.P.S. 2009
[N.Y.] Natural gas - Leak repair target - Local distribution company.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

83.
EXPENSES

s25
NY.D.P.S. 2009
[N.Y.] Natural gas - Leak repair - Treatment of costs incurred in excess or rate allowance - Local distribution company.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

84.
CONSERVATION

s
NY.D.P.S. 2009
[N.Y.] Natural gas local distribution company - Electric utility - Removal of disincentives to energy efficiency - Revenue decoupling mechanisms - Reconciliation and carrying charges.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

85.
GAS

s.
NY.D.P.S. 2009
[N.Y.] Energy efficiency - Removal of disincentives - Revenue decoupling mechanism - Reconciliation and carrying charges - Local distribution company .

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

86.

ELECTRICITY

s
NY.D.P.S. 2009
[N.Y.] Energy efficiency - Removal of disincentives - Revenue decoupling mechanism - Reconciliation and carrying charges.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

87.
REVENUES

s
NY.D.P.S. 2009
[N.Y.] Electric and gas utility - Removal of disincentives to energy efficiency - Decoupling of revenues from consumption - Reconciliation and carrying charges.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

88.
RATES

s80
NY.D.P.S. 2009
[N.Y.] Natural gas - Revenue decoupling mechanism - Reconciliation and carrying charges - Local distribution company.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

89.
RATES

s32
NY.D.P.S. 2009
[N.Y.] Electric utility - Revenue decoupling mechanism - Reconciliation and carrying charges - Local distribution company.

Re Central Hudson Gas & Electric Corporation

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P.U.R. Headnote and Classification

90.
AUTOMATIC ADJUSTMENT CLAUSES

s4
NY.D.P.S. 2009
[N.Y.] Revenue decoupling mechanisms - Reconciliation and carrying charges - Electric and gas utility.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

91.
AUTOMATIC ADJUSTMENT CLAUSES

s5
NY.D.P.S. 2009
[N.Y.] Revenue decoupling mechanisms - Reconciliation and carrying charges - Electric and gas utility.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

92.
RATES

s32
NY.D.P.S. 2009
[N.Y.] Electric utility - Revenue decoupling mechanism - Revenue per class model.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

93.
AUTOMATIC ADJUSTMENT CLAUSES

s4
NY.D.P.S. 2009
[N.Y.] Revenue decoupling mechanism - Revenue per class model - Electric utility.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

94.
REVENUES

s
NY.D.P.S. 2009
[N.Y.] Electric utility - Revenue decoupling mechanism - Revenue per class model.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

95.
RATES

s26
NY.D.P.S. 2009
[N.Y.] Electric utility - Hourly pricing program - Expansion to encompass smaller load customers - Threshold lowered to customers with 500 kW of demand.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

96.
RATES

s39
NY.D.P.S. 2009
[N.Y.] Electric utility - Kinds of service - Hourly pricing program - Expansion to encompass smaller load customers - Threshold lowered to customers with 500 kW of demand.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

97.
RATES

s26
NY.D.P.S. 2009
[N.Y.] Electric rate design - Hourly pricing program - Generation capacity charge - Method of determination.

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Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

98.
RATES

s33
NY.D.P.S. 2009
[N.Y.] Electric rate design - Special charges - Demand charges - Hourly pricing program - Generation capacity charge - Method of determination.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

99.
RATES

s25
NY.D.P.S. 2009
[N.Y.] Reasonableness - Ability to pay - Low-income program - Assistance to delinquent customers - Discounts for customers sacrificing to keep payments current - Electric and gas utility.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

100.
AUTOMATIC ADJUSTMENT CLAUSES

s4
NY.D.P.S. 2009
[N.Y.] Weather normalization clause - Calculation separate from revenue decoupling mechanism - Combined as line item on customer bills - Natural gas local distribution company.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

101.
CONSOLIDATION, MERGER, AND SALE

s3
NY.D.P.S. 2009
[N.Y.] Transfer of real property - From rate base to non-utility account - Obligation to file for commission approval prior to sale to third party - Filing required notwithstanding six-month holding period - Electric and gas utility.

Re Central Hudson Gas & Electric Corporation

P.U.R. Headnote and Classification

102.
EXPENSES

s0
NY.D.P.S. 2009
[N.Y.] Storm restoration costs - Incremental costs associated with ice storm - Deferral authorization - Electric utility.

Re Central Hudson Gas & Electric Corporation

Before Brown, chairman, and Acampora, Harris, Curry, Jr., and Larocca, Commissioners.

BY THE COMMISSION:

*1 *I. INTRODUCTION*

This proceeding was initiated in response to Central Hudson Gas & Electric Corporation's (Central Hudson's or Company's) filing on July 31, 2008 of tariff amendments reflecting an increase in rates and charges of approximately $35.4 million, or 16.3%, for electric delivery service, and $14.7 million, or 28.2%, for gas delivery service. [FN1]The filing called for the new rates to take effect on July 1, 2009, along with a one-year Electric Bill Credit (EBC) through which the Company would refund an estimated $21.2 million owed to its electric customers to mitigate the first-year impact of the rate increase. [FN2]

The Staff of the Department of Public Service (Staff) proposed numerous adjustments to the Company's proposal, having the aggregate effect of reducing the Company's requested increases for electric and gas delivery service to $16.1 million and $6.4 million, respectively.

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Staff opposed the use of an EBC, but recommended that some of the funds being held by the Company for the benefit of ratepayers be used to offset various non-recurring expenditures.

Central Hudson and Staff both also proposed the adoption of revenue decoupling mechanisms (RDM) as directed by our *Order Requiring Proposals for Revenue Decoupling Mechanisms* issued April 20, 2007. [FN3]The proposals differed in detail but shared the objective of removing disincentives to utility support of our efforts to promote energy efficiency and conservation.

Following a pre-hearing conference in September 2008, written testimony was filed in December by Staff and the U.S. Department of Defense and other Federal Executive Agencies (DOD/FEA) on behalf of the U. S. Military Academy at West Point (West Point). Four days of hearings were held from January 12 through January 15, 2009, with cross-examination conducted by representatives of the Company, Staff, DOD/FEA, the Consumer Protection Board, Multiple Intervenors (MI) and the Small Customer Marketer Coalition (SCMC). [FN4]

Following the hearings, initial briefs were filed on February 17, 2009, by the Company, Staff, DOD/FEA, MI and SCMC. The same parties filed reply briefs on March 11, 2009, as did the National Energy Marketers Association and the New York State Energy Marketers Coalition.

A Recommended Decision (RD) was issued by the judges on April 10, 2009. It reflected a revenue requirement of $33.1 million for electric service and $12.5 million for gas service. Despite adopting a number of adjustments proposed by the parties that reduced revenue requirement, as filed by the Company, the net effect of the recommendations was to lower the Company's requested increases for electric and gas service by less than $2 million and $3 million, respectively, due to the impact of the recently enacted Temporary State Energy and Utility Service Conservation Assessment which greatly increased the Company's obligation under Public Service Law Section 18-a (PSL §18-a).

Exceptions to the RD were filed by the Company, Staff, DOD/FEA and SCMC on April 30, 2009, and the same parties submitted briefs opposing exceptions on May 15, 2009.

Public Comment

*2 During this proceeding we have received comments from over 120 residents, businesses and public officials from Central Hudson's service territory. Nearly 100 contacted us by e-mail or through our website. Another 16 appeared in person and spoke at public statement hearings conducted on March 12, 2009, at the Poughkeepsie, New York, Municipal Building. Commissioner Acampora participated in the afternoon session of those hearings.

All of the individuals from whom we heard oppose any increase in rates for Central Hudson. Retired people and others living on fixed incomes expressed concern that rising utility costs for necessities such as heat and electricity were a severe burden. Many working people also complained that reduced employment opportunities and financial pressure on their employers to hold down wages and salaries put them in no better position to absorb increased rates than their retired counterparts.

At the public statement hearings, we also heard from representatives of the Town of Poughkeepsie and the Town of Marlborough, a member of the Dutchess County Legislature and the administrator of the Poughkeepsie water treatment facility. All expressed concern about the impact of a rate increase on governmental expenses and the pressure it would create for additional taxes at a time when their constituents can least afford them.

Subsequently, we have received letters in opposition to the rate increase from Dutchess and Greene Counties, the Towns of Esopus, Jewett and Wappinger, the City of Beacon, and the Villages of Athens and Red Hook. The letters included resolutions expressing opposition to the rate increase adopted by the Dutchess County Legislature, the Greene County Legislature, the Beacon City Council and the Town Board of Wappinger.

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The Orange County Partnership and the Rockland Economic Development Corporation also submitted letters. These did not address the proposed rate increases, but expressed continued support for funding by Central Hudson of the Hudson Valley Economic Development Corporation.

II. DISCUSSION

Having carefully reviewed the evidence; the arguments of the active parties; comments by interested public officials, organizations, and members of the public; and the recommendations of Advisory Staff, we adopt the recommendations of the RD with certain modifications which we identify in our analysis of contested issues set forth below.

Based on those recommendations, as modified, we authorize Central Hudson to increase its delivery rates for the year beginning July 1, 2009, by $38.0 million for electric service and $13.6 million for gas service. The revenue requirement schedules are contained in Appendix II and Appendix III. Although we have removed the effect of the increase in the PSL §18-a assessment from base delivery rates by instituting a separate surcharge, the authorized increase remains very close to that recommended in the RD. This is due to cost increases driven primarily by steep declines in the value of investments supporting the Company's pension and post-employment benefits programs.

*3 In order to mitigate the bill impact of the rate increase for electric service, we are also instituting an EBC. This credit on customers' bills will offset $20 million of the delivery rate increase during the rate year, and could ultimately provide $36 million of benefits to ratepayers over the next three years.

In addition, we approve the implementation by Central Hudson of Revenue Decoupling Mechanisms for both gas and electric operations.

Our analysis of the parties' principal exceptions to the RD follows.

A. ECONOMIC CONSIDERATIONS - AUSTERITY

[1-5] Citing significant weakness in the financial markets, and rising unemployment, as well as the record created at the Public Statement hearings and through other public inputs, the RD recommended three adjustments to the Company's requests in an attempt to create an appropriate, austerity-based rate allowance. The three issues on which the RD concluded that austerity concerns were paramount were: employee count (the RD recommended 830; Central Hudson requests 846); variable pay programs; and gas institutional advertising. These adjustments totaled $3.8 million on electric and $900,000 for gas.

The Company objects to the consideration of macroeconomic conditions which are not reflected in the record. It also excepts to the RD's finding that the amounts requested in these categories are reasonable, while simultaneously refusing to recommend them based on austerity concerns. Staff agrees with the RD's recommendations, but argues that the right result (*i.e.*, the revenue requirement reduction) was reached for the wrong reason (*i.e.*, austerity), inasmuch as the Company's proposed expenditures in these three categories could not be justified, in Staff's view, through a cost-of-service analysis.

Discussion - We agree with the RD's conclusion that rate allowances cannot be made in a vacuum. Central Hudson's exceptions to considering general economic information, fail to recognize that these concerns have been documented on an almost daily basis in publicly-available economic reports, were also raised by MI, and were repeatedly reflected in public comments received at the Public Statement Hearings and in writing. Our consideration of these issues is not only record based, but, in fact, we would be remiss in our obligation to the public interest were we to fail to take notice of the magnitude and depth of the current recession. Accordingly, the Company's exceptions are denied.

We are well aware of the 1980 Statement of Policy Concerning Evidence of Economic Impact in Rate Cases (Evidence of Economic Impact Policy Statement or EI Policy), and the austerity adjustment we will implement here is not inconsistent with that policy. Indeed, the EI Policy Statement explicitly recognizes that '[e]vidence of economic distress in a utility's service

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territory might be cited to support arguments for limiting a particular expense allowance to the low end of a range of reasonableness, where such a range exists.' [FN5] Thus, the Statement not only acknowledges that adjustments of this type may be taken, it also provides guidance describing the supporting evidence that might be offered in these circumstances, and how such evidence might be employed to evaluate 'the consequences of rate determinations for the economic circumstances of a utility's territory.' [FN6] Plainly, the EI Policy Statement, while critical of the information provided in earlier cases, does not preclude the use of the evidence before us today (testimony of parties, public hearing statements, publicly available statistics documenting the health of the State's economy) to establish the basis for the austerity adjustment we are taking here.

*4 When, as the RD, public comments and public information readily at hand demonstrate, our economy is experiencing extraordinary challenges and many consumers are taking any measures available to adjust their household budgets to reductions in available income, our rate decisions and, in particular, our decisions to increase rates should take account of the macroeconomic environment as it exists at the time of our decision. In a recent Consolidated Edison Company of New York, Inc. (Con Edison) order [FN7] we stated:

Expenditures that are reasonable during average or good economic times are not necessarily reasonable when economic conditions are extremely poor. When consumers are experiencing the extraordinary harsh economic realities we see today, a certain measure of frugality is properly expected from utilities and a reprioritizing of expenditures may be needed.

As this excerpt from our recent decision makes clear, an austerity adjustment responsive to the current macroeconomic conditions is not simply a reduction in the utility's revenue requirement that translates into an immediate and negative impact on the Company's rate of return. Rather, the need for austerity and its implementation calls for adjustments in the Company's priorities such that expenses, otherwise reasonable, are foregone or deferred. Once these short-term expense reductions are made, the resulting austerity adjustment translates these savings to rate savings for customers. Because there are actual savings associated with the austerity adjustments, there is no impact on the utility's earned rate of return on equity in the rate year.

While we agree with the RD's recognition that an austerity adjustment is appropriate under the current circumstances, we will not adopt the specific approach to austerity taken in the RD. With respect to the three areas highlighted in the RD for the austerity adjustment, we agree with Staff that reductions in those areas should be evaluated just as any other proposed cost-of-service adjustment to the Company's revenue requirement, and we provide our evaluations on those items in the body of this order. [FN8]

Accordingly, our approach to austerity will not single out a disallowance for any particular expense. Instead, in order to allow the Company greater flexibility to manage its resources, we will impute an austerity adjustment and leave the Company free to choose its own strategies for the achievement of the corresponding short-term expense reductions. This imputation, while consistent with the approach taken in the Con Edison case, [FN9] is based upon facts and circumstances specific to Central Hudson.

Central Hudson was required by our May 15, 2009, notice in the generic austerity case [FN10] to provide a description of the measures it has already taken for austerity purposes and to describe any cost control measures it may undertake in the coming year. We have received the Company's filing (June 15 Report) and it is consistent with much information that is already on the record. More specifically, because of constraints outside of its control, the Company has, over the past three years, successfully developed and implemented several significant measures to restrain expenditures. While some of these items may be viewed as temporary austerity measures, others represent more permanent solutions addressing the structural causes of certain costs.

*5 The June 15 Report in the generic austerity case also describes several cost-control measures Central Hudson may undertake in the coming year. These include the deferral of certain capital expenditures, reductions in re-

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search and development expenses, caps on certain executive salaries, and reductions in other operation and maintenance expenditures. [FN11]At this stage, while we can comment on certain aspects of the Company's June 15 Report, we are not able to fully evaluate the nature and scope of all of the Company's specific pro-forma measures. Nevertheless, we recognize Central Hudson's overall filing as a good faith effort to respond to the need for significant cost controls and austerity measures and we commend the Company for its prompt and complete response.

In light of our specific discussion of austerity in this case, and of the Company's efforts through this filing to meet the need for an austerity program, we will address the Company's June 15 Report filing in this proceeding. We expect the Company to supplement the June 15 filing with the additional information which we describe below as soon as possible.

Using the size of the adjustment specified in the Con Edison case as a starting point, and considering the unique circumstances of this Company, we conclude that the austerity adjustment goal for Central Hudson in this case should be in the amount of $2.4 million for electric operations and $0.6 million for gas operations. These amounts represent approximately 1.8% of the Company's non-fuel operation and maintenance expenses for electric and gas operations, respectively, and as such represent half the percentage than we applied in Con Edison. We will measure the success of Central Hudson's austerity program against this lower percentage because of the record evidence and information in the June 15 Report indicating that the Company has already taken significant steps to reduce expenses through both austerity like measures and more permanent cost control solutions.

Our approach to the austerity adjustment and to the underlying expense reductions is one which recognizes that the best efforts implementation of the adjustment will identify expenses which, when foregone in the short term, may impose costs on ratepayers in the future. The Company's strategy for implementation of the adjustment should take care that these future costs are not disproportionate to the short-term savings provided to ratepayers though the adjustment. In addition, we expect that any austerity savings taken by the Company will not result in a direct impairment of the Company's programs to provide safe and adequate service. [FN12]

To assure these considerations are appropriately considered in the Company's plans, we direct Central Hudson to identify as promptly as possible the capital and expense reductions which it will be using to implement the austerity program and the impacts, if any, on service quality which may result from these reductions. In addition, the Company should identify and quantify future costs or increases in the Company's revenue requirement in later periods which may result from the capital and expense reductions which it is taking in the present rate year. Finally, the Company should identify each capital and expense reduction that it considered, but decided not to include, as part of its austerity program and the reasons why the proposed reduction was not included.

*6 Consistent with the implementation of the austerity goal specified in the recent Con Edison case, we recognize that the Company's best efforts may not realize the full amount of the austerity adjustment taken in this order. Accordingly, we will allow the Company to petition at the end of the rate year for a deferral corresponding to that amount of the austerity-related expense reductions which, despite the Company's best efforts, has not been realized. Following an evaluation of whether the Company used best efforts to achieve the full $2.4 million electric and $0.6 million gas savings reflected in rates, we would make a decision as to the amount of deferral, if any, to allow. This approach allows the Company the flexibility to manage its own resources in light of our current austere environment. It also helps to assure that the size of the adjustment, when implemented, corresponds to the size of the short-term savings the Company, using best efforts, will actually realize.

We fully expect the Company to use its best efforts to achieve the entire imputed revenue requirement reductions. Nevertheless, as we previously noted, the circumstances in this case do not offer the same breadth of opportunity for savings as we recognized in our Con Edison decision. Accordingly, in this case, we will place no

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minimum on the amount of austerity savings that must be achieved by the Company to qualify for deferral treatment. The Company should understand that it will have to carry its burden in establishing that despite its best efforts, cost cuts could not be achieved to make the full $2.4 million electric and $0.6 million gas revenue requirement reductions. However, with this demonstration, we recognize that up to the full amount of the austerity adjustment may become a deferral that the Company may seek to recover in its next rate case.

The June 15 Report and the additional information described above to supplement the June 15 Report will be evaluated and addressed as part of the compliance process for this order. If Staff and the Company, after evaluating the comments, if any, from other parties, agree that the measures identified by the Company will implement an austerity program in a form and an amount consistent with this order, Staff shall file with the Secretary on notice to all parties, its statement reflecting such agreement. If Staff and the Company cannot reach such an agreement, Staff shall, on notice to all parties, forward its recommendations to the Commission for the resolution of such dispute.*B. OPERATING REVENUES*

1. Sales Forecasts

[6] Staff takes exception to the RD's recommendation that the degree day inputs to the models used for forecasting sales should be derived from Central Hudson's monthly regression analysis rather than the 30-year averages on which Staff's forecasts were based. It argues that the linear trend lines generated from the aggregated annual numbers presented in Exhibit 85, which the RD found persuasive, are *not* the same as the monthly trends generated by Central Hudson's forecasting methodology. Staff says that Exhibit 91 shows the Company's numbers to be much less persuasive. Staff also reiterates its argument that the trend toward warmer weather remains weak and does not justify a change in forecasting methodology. It acknowledges that the Energy Information Administration of the U. S. Department of Energy (EIA) has shifted to a 10-year average for forecasting purposes, but says that shift does not validate Central Hudson's much different forecasting methodology.

*7 In response, Central Hudson explains that Exhibit 85 does, in fact, reflect the degree day data it used by for its forecast. It says the RD was correct in concluding that the Company's method better reflects recent degree day trends.

Discussion - In order to establish reasonable rates for Central Hudson, we have to forecast the total volume of electricity and gas that the Company can be expected to deliver during the rate year. Because those deliveries are heavily influenced by weather, the models we use must incorporate some estimate of the heating and cooling degree days that the service territory is likely to experience.

As the RD noted, we are not in the weather forecasting business, and cannot predict the actual weather for the rate year any better than the National Weather Service. Our objective, rather, is to choose degree day inputs for the forecasting models that are not inherently biased and are, therefore, likely to provide a reasonable projection of what sales in a 'normal' year should look like.

The RD concluded that the 30-year average of historic degree day experience that we have customarily relied on no longer appears to satisfy this objective. It found that compared to actual experience over the 15 years ending 2007, the 30-year average overstated heating degree days (and understated cooling degree days) about two-thirds of the time, while both the Company's methodology and the 10-year average now used by EIA showed no such bias.

We agree with the RD that a change is appropriate given recent experience, but we disagree with its selection of Central Hudson's approach. As Staff pointed out, the 30-year average has historically served us well and has had the advantage of providing a simple, easily applied rule based on readily available data. Any change in the way we obtain the degree day inputs for our forecasting models should retain that simplicity.

Therefore, consistent with the approach taken by the EIA, we will adopt the most recent 10-year averages for

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purposes of providing heating and cooling degree-day inputs to the sales forecasts in this case. Furthermore, we expect these averages to be utilized for forecasting purposes in future rate filings.

2. Finance Charge Revenue

[7] Central Hudson states that the calculation of an increase in finance charge revenues resulting from an authorized rate increase should be based on the cash increase in rates, that is, the portion of revenue requirement not funded from deferral accounts. The clarification is appropriate and is granted.

3. Update

[8] Staff argues in its Brief Opposing Exceptions that Central Hudson's revision of its sales forecasts went beyond the application of revised values of forecast drivers to equations already on the record. It says the Company impermissibly reestimated its forecasting equations and added or dropped variables. It recommends that the previously agreed-upon customer count be retained with updates allowed for April 2009 macroeconomic data and for the Company's projection of EEPS-related sales reductions.

*8 *Discussion* - We adopt Staff's position. The RD's call for an update of the sales forecasts concurrent with the filing of the Company's Brief on Exceptions was not an authorization for wholesale revision of the equations themselves. The RD also authorized an update reflecting the impact of EEPS, and Staff acknowledges that the Company's estimate is consistent with its own.

C. OPERATING EXPENSES

1. Directors and Officers Liability (D&O) Insurance

[9] The RD found that the overall level of D&O insurance coverage was appropriate and recommended that the full cost of the premium be allowed in rates. Staff does not disagree with the finding as to the level of coverage, but takes exception to the requirement that ratepayers bear the entire expense. It points to our Con Edison Order in which we found that this insurance coverage benefits both ratepayers and shareholders, and it argues that the 50-50 sharing of cost responsibility we ordered there should be adopted here.

The Company responds that no evidence was presented in this case to support a split of responsibility for premiums that the RD found were reasonably incurred business expenses.

Discussion - The Company's argument misses the point. We acknowledged in our Con Edison Order that there is:
no particularly good way to distinguish and quantify the benefits of D&O insurance to ratepayers from the benefits to shareholders. [FN13]

In other words, we adopted the 50-50 sharing for Con Edison precisely because there was no empirical basis for determining the relative value of the benefits of this type of insurance to ratepayers and shareholders.

We have the same situation in this case, and we adopt the same resolution. Accordingly, Staff's exception is granted, and we direct that one-half the cost of the premiums for D&O liability insurance be excluded from rates.

2. Labor

a. Employee Count

[10] The RD found the Company's requested employee level of 846 to be reasonable, but recommended against an increase above the historic level of 830 due to economic and austerity considerations as discussed above. The Company excepts to the refusal to allow costs for a 'reasonable' number of employees. Staff agrees with the result, but argues that its adjustment be adopted without relying on austerity.

Discussion - The Company's most recent updates reflect an employee count of 840. In our view, allowing this updated actual number of employees provides the Company a reasonable allowance for employee costs for the rate year before considering the poor economic climate.

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In addition, this employee level represents a compromise between the litigated positions of Staff and the Company. Further, allowing the actual, current employee level may present further opportunities for austerity savings. Accordingly, the Company's exceptions are granted to the extent of allowing 840 employees without austerity.

b. Variable Pay

[11] The RD recommended that a rate allowance for the cost of Central Hudson's variable compensation programs be disallowed. It concluded that in the current difficult economic circumstances the cost of this program could not be considered a reasonable and necessary business expense.

*9 Staff takes exception not to the RD's recommendation, but to its reasoning. It points to information included in Exhibit 144 which it says demonstrates that the metrics of the plans favor shareholders over ratepayers. Staff also argues that the Company has made no showing that the programs generate savings for ratepayers commensurate with their cost.

Central Hudson opposes disallowance of this expense on the austerity grounds found by the RD, and argues that if the variable compensation program were viewed in a normal context, its cost would be included in rates. It says that proper rate-setting balances the interests of ratepayers and shareholders, and that the standard suggested by Staff is too one-sided.

Discussion - Central Hudson has three incentive compensation plans. The first, an executive plan covering 12 top officials of the holding Company and the utility represents approximately 56% of the incentive pay for the rate year. The second, called a Performance Incentive Plan represents about 20% of the projected incentive pay expense and covers the general body of management employees, approximately one-third of the total work force. The third plan provides incentive compensation for 16 top managers and makes up 24% of the cost of the incentive pay programs.

Exhibit 144, cited by Staff, includes excerpts from Company documents which show that the primary target for each of the variable compensation plans relates to the reduction of operating expenses. We have previously stated that when the goals of an incentive plan are designed to reduce costs, and those cost reductions are not reflected in revenue requirement, the result is a windfall for shareholders at ratepayer expense. [FN14]Customers pay for the effort required to achieve benefits that flow through to the Company's bottom line.

We reiterated this concern in our recent Con Edison Order, in which we endeavored to make it very clear that: [Our] policy that such [variable compensation] plans must be self-supporting through productivity savings or financed by shareholders applies to any incentive plans that *include* financial parameters. [FN15]

We agree with Staff that such a showing has not been made by Central Hudson in this case. Accordingly, we clarify that our adoption of the RD's recommendation is based on our evaluation of the merits of the case presented by the parties, and not current economic circumstances. [FN16]

c. Update

[12] In its Brief Opposing Exceptions, Staff states that Central Hudson updated the historic test year from March 31, 2008, to March 31, 2009. It says no such update was agreed to or authorized by the RD.

Discussion - No justification for this otherwise unauthorized update has been presented. Updated figures for this expense category will reflect the use of the original historic test year as the starting point.

3. MGP Expense

[13] Central Hudson requested a rate allowance of approximately $8.0 million, as updated, for the cost of site investigation and remediation associated with former manufactured gas plants (MGP expense). No party contested the importance of the Company's pursuit of this environmental clean-up effort, or the need to ensure that

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Central Hudson is compensated for costs reasonably incurred in the process. Staff, however, contended that there was considerable uncertainty as to the actual outlay that would be required during the rate year. It proposed that the allowance be set at the level of the average expenditures of $2.8 million incurred by the Company over an historic three-year period, and that the electric component of any excess costs actually incurred during the rate year be offset against the existing net regulatory liability carried on the Company's balance sheet.

*10 The RD adopted Staff's proposal. Central Hudson excepts, arguing that the RD recognized that MGP expenditures would likely exceed the historic average, and that it should have been given at least a $5 million rate allowance, rather than a balance sheet offset.

Discussion - As noted in the RD, 92% of the MGP expense anticipated by the Company is associated with a single site located in Newburgh. The use of accumulated funds held for the benefit of ratepayers, and subject to Commission disposition, is entirely appropriate for the type of nonrecurring, project-specific expenditures characteristic of MGP site remediation efforts. This approach moderates the required rate allowance, which may persist well beyond the completion of the project, while assuring that the utility is fully compensated. The Company's exception is denied.

4. Other Environmental Expense

The RD noted that the requested increase in the rate allowance for this expense category (in excess of inflation) was ostensibly based on the need to fund certain specific projects identified by the Company's Director of Environmental Services. What those projects were, and why they were needed in the rate year, were never explained, according to the RD. Apparently, that information was shared among the parties in discovery, but was not offered in evidence by the Company. As a result, the RD concluded that there was no articulated support for recommending any increase in environmental expense beyond Staff's proposed escalation for inflation.

Central Hudson takes exception to this conclusion arguing that Staff never presented any evidence that the projections of the Company's environmental director were in error. It also contends that Staff made improper adjustments or ignored relevant data in calculating the three-year average it used to normalize the test year expense, and that its use of an historical average was inappropriate because the annual numbers showed an increasing cost trend. Finally, the Company asserts that it was unfair for the RD to give Staff an opportunity to clarify its position on storm restoration expense without allowing Central Hudson to provide more information on its environmental expense proposal. Therefore, it attaches its responses to Staff information requests to its Brief on Exceptions.

Staff responds that the fundamental purpose of a normalizing adjustment is to ensure that the base for forecasting rate year expense reflects expected expenditures and is not distorted by costs that are unusual. It adds that the data pointed to by the Company as evidence of an increasing cost trend actually reflects MGP expenditures, which are not included in the separate environmental expense account.

Discussion - Staff had no obligation to present a case refuting the sufficiency or validity of proposals the Company itself chose not to offer. No information concerning the projects proposed by the Company's Director of Environmental Services was available for the Recommended Decision. Further, the information clearly could have been submitted well in advance of the RD, as the attachments to the Company's brief establishes. Under the circumstances, we are not obliged to consider this late filed evidentiary proffer, and, in the exercise of our discretion, it will not be considered in this proceeding. The Company's exception is denied.

5. Regulatory Commission Expense

*11 **[14, 15]** The recent amendment of PSL §18-a, substantially increased the assessments payable by all utilities. We addressed the recovery of this additional expense for the first time in our Con Edison Order, which was issued two weeks after the RD in this case. Sub-

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sequently, we instituted a proceeding to consider the matter on a generic basis. [FN17]

Discussion - In the generic proceeding regarding PSL §18-a, we are issuing a ruling concurrently with the Order in this rate case adopting a surcharge to recover this expense in a manner similar to the method approved for Con Edison. Given the many issues involved in the generic proceeding, we will let its implementation establish a surcharge for Central Hudson. For the General Assessment designed to recover the Department of Public Service's costs, we will allow in base rates the most recent estimate available from Staff.

6. Right-of-Way Maintenance-Distribution Expense

According to Staff, Central Hudson included a new amount for right-of-way maintenance-distribution expense in updates submitted with its Brief on Exceptions. Staff contends that the update was not authorized by the RD and should be rejected.

Discussion - Staff is incorrect. The number included in the income statements submitted by Central Hudson with its Brief on Exceptions is not an update. It is the same amount that the Company presented in its direct testimony, as corrected on the record at the hearing. No party raised any issue concerning this requested rate allowance in its trial briefs, and there was no reason for it to be addressed in the RD. Staff's belated objection is untimely and is denied.

7. Storm Restoration Expense

[16] The parties agreed that a rate allowance for the cost of restoration of service from storm-related outages should be based on a three-year average of actual expenses incurred, and that the average should be updated at the time of the Company's filing of its Brief on Exceptions. They disagreed, however, as to what should be included in the average. Staff argued that 'anomalies' should be excluded. The Company found that standard to be unfairly vague.

The RD expressed concern with the subjective nature of Staff's proposed adjustment, but also recognized that inclusion of a truly anomalous event could unreasonably inflate the rate allowance. Consequently, it authorized Staff to explain in its Brief Opposing Exceptions what costs it would propose to remove from the average and why. The Company took exception to this provision on the grounds that Staff had not previously been able to articulate a standard for identifying anomalies, and that Central Hudson would not have a chance to respond.

In its Brief Opposing Exceptions, Staff proposed to exclude only one storm event from the average, a December 11, 2008, ice storm. It also reported that it would support the Company's request in Case 09-M-0004 for deferral of the costs associated with that storm. [FN18]A stipulation embodying that support and requesting that we grant the deferral petition was subsequently submitted, and we will address it separately below.

***12** *Discussion* - The stipulation submitted by Staff and the Company did not explicitly resolve the issue of an appropriate rate allowance for storm restoration expense. To the contrary, it expressly provided that neither party was required by the agreement to abandon any position taken on the issue in this case.

Whether or not any actual dispute remains, however, we find that the use of a three-year average excluding the ice storm of December 11, 2008, is appropriate.

Inclusion of particular storm costs in the average used for establishing the rate allowance for restoration expense is an implicit statement that the utility is expected to fund recovery related to storms of that type and magnitude from the amount provided in rates. Approval of a petition for deferral of recovery costs, on the other hand, is an acknowledgement that costs of that magnitude were not contemplated when rates were set. Either funding method, inclusion in the rate allowance or deferral accounting, will enable the utility to recover its costs, but the two methods cannot coincide. Therefore, it was appropriate to exclude the cost of the 2008 ice storm, for which we will authorize deferral, from calculation of the allowance in this case. Central Hudson's exceptions are denied.

8. Stray Voltage Expense

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[17, 18] The RD recommended that the rate allowance for stray voltage expense include an amount estimated by Central Hudson for incremental costs associated with expanded requirements imposed by our December 15, 2008, Order Adopting Changes to Electric Safety Standards, [FN19] but reduced the amount by one-half of the adjustment proposed by Staff to reflect the fact that the Company's estimates have historically been overstated. Given the uncertainty of this approximation, the RD also recommended continuing the Company's existing authorization to use deferral accounting for this expense until Central Hudson completes one full cycle of stray voltage testing under the new rules.

Staff excepts, arguing that deferral accounting should be handled on a petition basis as under the original stray voltage testing order, is not appropriate for a one-year rate case, and is not necessary because there is now an expense history for this function on which to base a reasonable forecast. Staff also contends that the basis for allowing only one-half of its recommended adjustment is not clear.

Discussion - As noted, deferral accounting for this expense is currently approved for Central Hudson. The question is whether to continue it. Given the uncertainty associated with the new requirements, it is reasonable to do so for one testing cycle, after which better estimates should be possible. Reduction of the Company's request by one-half of Staff's proposed adjustment was a compromise between the reality that the new requirements will increase costs, and the likelihood that Central Hudson's estimates of those increases will prove to be high. Staff's exception regarding deferral is denied.

*13 *9. Transmission Sag Mitigation Program - Expense Component*

[19] A study conducted by Central Hudson in 2006 determined that a number of the Company's transmission circuits do not meet National Electrical Safety Code clearance requirements for pedestrian paths, roadways and other facilities. Severe problems will require the replacement of poles and towers with higher structures. Less extreme discrepancies can be corrected by re-tensioning lines. Central Hudson included a rate year request of $1.1 million for expenses related to re-tensioning, based on a projected cost of $3.3 million over three years.

No party questions the importance of the Company's undertaking this safety-related program or the overall cost estimate. Staff, however, takes exception to the RD's recommendation that Central Hudson be permitted to charge a fixed $1.1 million per year for re-tensioning expense against available credits. It contends that this approach will not provide adequate incentives for cost control, and recommends instead that the annual charge allowed be equal to the lesser of the estimated re-tensioning related costs or the actual expense incurred.

Discussion - Staff's exception is denied. We do not consider such a one-way true-up mechanism to be necessary for this expense. The transmission sag mitigation program is a discrete, multi-year project that we expect the Company to complete. The total estimate for the expense portion of the cost of this project, $3.3 million, is undisputed, and the RD recommended, consistent with Staff's position, that the Company be allowed to fund it from available net credits rather than an allowance in rates. Cost control is provided by putting a $3.3 million cap on the total amount the Company is authorized to charge against those credits. Beyond that amount, Central Hudson will have to obtain Commission approval for a deferral or an additional rate allowance in some future case. If the Company under spends the allowance, a portion of the net credits will continue to be held for ratepayer benefit.

10. Uncollectible Bill Expense

[20] The RD recommended that the rate allowance for this expense be based on the most recent data available prior to the issuance of our order, but denied the Company's request for authority to defer and reconcile excess expenditures. It noted that the Commission was considering the impact of growth in this expense category on a generic basis in a separate proceeding; that declining commodity prices should help moderate the problem; and that the update authorized should provide the Company with a reasonable rate allowance.

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Central Hudson takes exception to the denial of deferral authority.

Discussion - The RD was correct in explaining that automatic deferral authority, while frequently provided in negotiated multi-year rate plans, is normally not necessary for a one-year rate case, absent unusual circumstances. Basing the rate allowance for uncollectibles on the Company's most recent experience ensures that the amount is reasonable. The Company also has access to our normal procedures for requesting deferral authority, should that become necessary. In addition if our pending proceeding finds that further measures are required, Central Hudson will be able to avail itself of them. The exception is denied.

D. TAXES

1. Property Taxes

***14 [21-23]** The RD recommended rejection of Central Hudson's request for bilateral reconciliation of property tax costs on the ground that an update of the forecast expense prior to an order would be sufficient for a one-year rate case. It also found that a mechanism providing for the sharing of property tax litigation related legal expenses between the Company and ratepayers made sense, but recommended that it not be adopted at this time.

Central Hudson takes exception, arguing that both these recommendations are inconsistent with the recent Con Edison Order which approved deferral and reconciliation of property taxes in that one-year case because of the uncertainties generated by the weak economy. That Order also expressed support for aggressive legal action to lower taxes. [FN20]

Staff agrees with the RD's conclusions but takes exception to the suggestion that the litigation cost sharing mechanism might be worth exploring further in future proceedings. It argues that the Con Edison Order dealt with a unique situation in which property taxes accounted for nearly 33% of the rate increase as compared with less than 1% for Central Hudson in this case.

Discussion - In Con Edison, we were dealing with extraordinary increases in property taxes imposed by the City of New York, representing fully 29% of the utility's total revenue requirement. [FN21]An underestimation of the proper rate allowance for this expense category, given the current economic volatility, could have had a serious adverse impact on Con Edison's finances.

Here, property taxes account for only about 10% of the Company's revenue requirement, and there is no indication of any unusual movement toward higher assessments or rates in Central Hudson's service territory. Consequently, we find that the RD's recommendation that the Company be allowed to update the allowance for this expense based on the latest information available, combined with our standard policy on requests for deferral authority, provides Central Hudson with a reasonable rate allowance. The Company's exception on this point is denied. [FN22]

With regard to property tax litigation expenses, we ordinarily allow reimbursement of such costs from the proceeds of successful tax challenges prior to sharing the balance with ratepayers. This provides an appropriate incentive to pursue cases having a reasonable chance of success, without promoting litigation for litigation's sake. Therefore, we deny the Company's exception. If the Company wishes to propose a different approach in the future, it is free to do so.

2. Avoided Cost Interest Capitalized

[24] The RD recommended adoption of Staff's adjustment to the rate allowance associated with this item. Central Hudson excepts saying that it determined the amount included in its filing by following the formula set forth in the Commission's 1988 policy statement addressing the requirements of the Tax Reform Act of 1986. [FN23]Staff argues that the policy statement merely provided an example of the normal calculation; that Central Hudson needed to take into account the nature of its actual financing activities related to its capital program; and that it did not do so correctly.

***15** *Discussion* - This issue involves timing differences

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in the recognition of income taxes created by differing tax and rate accounting rules governing the capitalization of interest expense. The example included in the policy statement cited by the parties was intended to illustrate the treatment of avoided cost interest capitalized for typical utility financing of capital projects. It was not designed as a template to be used regardless of the tax implications of the Company's actual financing of its capital projects. The RD correctly recognized that Staff's adjustment produces the desired result of matching the benefit of the interest deduction for tax purposes with the recovery of the associated capitalized interest. The Company's exception is denied.

E. RATE BASE - CAPITAL EXPENDITURES

1. Capital Expenditure Targets

[25, 26] Staff proposed a number of capital expenditure target mechanisms having certain characteristics in common: (i) establishment of a fixed expenditure target based on Central Hudson's capital budget; (ii) recovery for the benefit of ratepayers of the revenue requirement effect, including carrying charges at the pre-tax rate of return and associated depreciation expense, of any shortfalls in expenditures; and (iii) no automatic deferral of carrying charges and depreciation for over expenditures. Staff says these measures provide an incentive both for cost control and for the completion of needed capital improvements.

The RD found that (a) no evidence had been presented to indicate any problems with the management of capital expenditures by the Company in the past that would warrant these mechanisms; (b) the resulting targets materially alter the purpose of the capital expenditure budgets prepared by the Company; and (c) the mechanisms are misaligned with the interests of ratepayers in that they create both an incentive to overestimate capital costs in the future, and a disincentive to achieve cost savings in the execution of projects. The RD acknowledged the risk that the utility could postpone capital projects in the short run to enhance earnings, with possible long-term detriment to the infrastructure, but suggested that this could better be addressed through effective monitoring of capital construction rather than budgeting.

Staff excepts arguing that (a) the RD's monitoring solution provides no remedy for ratepayers if underspending actually occurs; (b) the notion that Central Hudson's incentive to reduce costs would be diminished is purely speculative, and no evidence was presented quantifying capital savings achieved through management of capital projects in relation to cost forecasts; (c) the proposals do not increase business risk because they eliminate costly prudence investigations; and (d) similar measures have been adopted for both Con Edison and Orange & Rockland Utilities.

Discussion - On this issue, we fundamentally disagree with the RD. As Staff notes, we have adopted these capital expenditure target mechanisms, with the one-way true-up feature for both Con Edison and Orange and Rockland. They provide necessary protection for ratepayers against both over and under expenditures, and are appropriate even for utilities with no prior history of missing spending forecasts.

***16** The RD's concern that the deferral of the revenue requirement effect of under expenditures for the benefit of ratepayers may diminish the Company's incentive to control costs, or cause it to inflate its budget estimates, is unwarranted. Under Staff's proposals, if the Company overspends, it receives no immediate return on the excess outlay. If it underspends, it loses a return on part of the allowance in rate base, but it has not had to make any investment to support that portion of the allowance, and has lost nothing out-of-pocket. Therefore, the Company is considerably better off coming in under budget and has a strong incentive to do so. Furthermore, the one-way downward true-up assures that it cannot benefit at ratepayers' expense by unnecessarily inflating its budget.

Accordingly, we grant Staff's exceptions and adopt the target and deferral mechanisms it proposed for electric, gas and common plant, with the associated reporting requirements.

2. Spackenkill Substation

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[27] In response to the RD's request for an updated schedule for completion of this project, Central Hudson stated that it did not expect the Spackenkill Substation to be placed in service prior to June 2010. It agreed with the RD's recommendation that the project be removed from rate base and accrue carrying charges at the pre-tax rate of return based on actual project costs.

Staff excepts to the Company's being allowed to update its forecast in-service date, and to the allowance of carrying charges on costs that could exceed the forecast amount included in the rate filing. Staff also, in effect, requests clarification that deferral will be permitted only if the station is put in service during the rate year, contrary to the Company's interpretation of the RD.

Discussion - Staff's first exception is moot in that the Company's update did not change its previous forecast. Its request for clarification and its exception concerning the deferral of carrying charges are granted. Deferral is authorized only on the lesser of the actual cost incurred by the Company for this station, or the $6.7 million rate base allowance, and then, only if the station is placed in service during the rate year.

3. Transmission Sag Mitigation Program - Capital Component

[28, 29] As noted above, there is no dispute as to the need for this program which is expected to continue into 2012. For the rate year, Central Hudson proposed to replace 213 transmission line structures at an estimated cost of $6.2 million. The total program will encompass approximately 810 replacements at a cost of about $23 million. Staff proposed a specific target and true-up mechanism for the rate year which the RD concluded was unnecessary.

Discussion - We do not find it necessary to discuss in detail the various arguments and counterarguments presented by the parties concerning the need for a target mechanism specific to this program. As we stated above, the transmission sag mitigation program is a discrete undertaking important to safety that we expect the Company to complete in accordance with the schedule it has proposed. The potential for gaming of earnings through the timing of replacements is, therefore, minimal because any under expenditure in the rate year will eventually have to be made up in later years in order for all the required replacements to be made. To enable us to track those expenditures and ensure that the costs for which ratepayers are responsible are justified, we direct that the carrying charges and depreciation expense associated with any over or under expenditures be deferred subject to true-up upon completion of the program.

*17 *4. Earnings Base/Capitalization (EB Cap) Adjustment*

[30, 31] Central Hudson takes exception to the RD's recommendation that the Company be required to provide better information concerning the factors underlying changes in its EB Cap adjustment in future rate filings. It says the recommendation seems to require a lead/lag study, which we have previously found to be unnecessary.

Discussion - We deny the exception, but clarify that no specific study is required. The Company is simply directed to provide sufficient information to give our Staff a clear understanding of the drivers of changes in the EB Cap adjustment from case to case.

F. DEPRECIATION

1. Depreciation - Gas Plant

[32, 33] The RD discussed three methods of accounting for negative net salvage associated with the retirement of long-lived gas distribution mains and services. The Company advocated 'standard' depreciation, which recovers the projected negative net salvage cost over the life of the asset. Staff supported fixing the negative net salvage rate permanently at 60% of original cost for depreciation purposes, with the balance of the actual net cost of removal expensed currently. The RD recommended continuation of the approach adopted in the Company's last rate case, which also provided for the negative net salvage rate to be fixed at 60% and a portion expensed, but allowed any excess removal costs over and above the amount expensed to be charged to the depreciation reserve.

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The Company takes exception to the RD's recommendation, repeating its contentions that the methodologies it proposes are 'standard' and avoid intergenerational inequities. It also argues that the RD erred in not adopting its proposal to increase the negative net salvage rate for gas services to 70% in light of evidence that the actual rate is already substantially higher.

Staff also takes exception, pointing out that the method recommended by the RD has never been accepted outside of a negotiated settlement, while Staff's proposed treatment of net salvage for these accounts was applied to Central Hudson for many years prior to adoption of the current rate plan. The expensing of excess costs of removal, Staff notes, helps to mitigate the impact of inflationary growth in net salvage expense on the size of the depreciation reserve deficiency which ratepayers may be required to support for decades before retirement of these long-lived assets.

Staff also responds to the suggestion that the current net salvage rate for gas services be increased from 60% to 70% by stating that it does little to address the core problem of the impact of inflation on removal costs, while increasing current depreciation rates.

Discussion - We find that the RD's effort to recommend a middle ground between Staff and Company positions was misguided in this instance. The treatment of negative net salvage it recommends was uniquely the product of a negotiated, multi-year rate plan in which less than ideal provisions in one area may have been acceptable in light of the net value of the overall package. We continue to share Staff's concern for constraining growth in the depreciation reserve deficiency driven by inflationary pressure on removal costs, which our pre-rate plan methodology was intended to address. Accordingly, we grant Staff's exception, adopting its proposal for the current expensing of excess negative net salvage.

***18** For the same reasons, we also deny the Company's exception to the RD's failure to recommend an increase in the negative net salvage rate from 60% to 70% of cost. This change will increase depreciation expense while doing little to stem the growth of the depreciation reserve deficiency.

2. Depreciation - Electric Plant

[34, 35] The RD adopted Staff's position concerning the average service lives and/or survivor curves for ten electric accounts. It found, in essence, that we are not required to accept the judgment of the Company's expert witness concerning likely changes in the historic pattern of retirements as being superior to the conclusions reached by Staff through evaluation of the historical results. It also recommended adoption of Staff's proposed reduction in the negative net salvage rates for 13 accounts based on Staff's analysis of actual costs incurred over the most recent five years.

Central Hudson excepts as to service lives and retirement curves, saying that both the Commission and NARUC have found that it is appropriate to consider new factors influencing plant retirements in addition to merely relying on past history. On net salvage, it says the RD inappropriately provides an amount for negative net salvage that reflects only current activity and not the expected cost over the life of the assets.

Discussion - We are not persuaded that the RD erred in concluding that the judgment of the Company's expert witness does not necessarily produce a more accurate forecast of depreciation than that recommended by Staff. We also agree that there is nothing extraordinary about Staff's use of recent historic data as a check to ensure that allowances for net salvage received by Central Hudson reflect its actual requirements. The exceptions are denied.

3. Depreciation - Common Plant

[36, 37] Initially, the Company proposed significant reductions to the amortization periods for six common accounts. Based on its comparison of the periods currently used by the Company with those used by other utilities, Staff recommended no change. The RD proposed a middle ground, bringing Central Hudson's amortization periods closer to the average lives used by the other utilities.

Central Hudson takes exception to that recommenda-

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tion. It argues that it should be authorized to use the same amortization periods as Con Edison, which, it says, have been closely scrutinized in recent cases. Also, the Company points out that various sub-accounts within the six common accounts addressed by the RD have amortization periods that are substantially different from both those proposed by either the Company or the RD. Finally, it says that if its proposal is not approved, the existing service lives should be continued; that is, Staff's position should be adopted.

Staff responds by pointing out that the Con Edison service lives are the lowest of all the options presented, and it expresses support for the RD's recommendation.

*19 *Discussion* - Central Hudson's exception suggests that its original proposal was either incomplete or misleading. The Company initially asked for a reduction in the amortization period for account 391 from 8 to 5 years, but now shows that sub-accounts within that account had service lives of 8, 12 and 20 years. A five-year amortization period for such an account is not reasonable. Given this lack of detail, we decline to approve the Company's proposal and instead adopt Staff's original position that no change in amortization periods be made at this time.

G. DISPOSITION OF DEFERRED ITEMS

1. Electric Bill Credit

[38, 39] No party disagreed with Central Hudson's proposal to net certain deferred debits and credits (also known as regulatory assets and liabilities). For electric operations, this process will leave a net liability owed to ratepayers, which the Company proposed to pay out to customers over the rate year as an electric bill credit. The RD adopted the EBC concept, but recommended that the funds be paid out in equal installments over three years in order to reduce the possibility of 'bill shock' from expiration of the credit, or at least to postpone it until hoped-for better economic circumstances have arrived. The RD also noted concerns about the fairness of the method proposed by the Company for allocating the EBC among rate classes, and asked the parties for further comment.

In response, no party takes exception to the EBC approach, but several suggest modifications to the mechanism as proposed in the RD. Staff recommends that some portion of the available credit be retained for future rate mitigation, and that the EBC be phased, with the largest payout in the first year and progressively smaller credits in subsequent years. Multiple Intervenors opposes Staff's call for retention of part of the available credit, but could support the phasing proposal. Central Hudson continues to call for full payout in the rate year.

With respect to allocation of the credit among classes, Staff supports apportionment in the same manner as any rate increase authorized for electric delivery service. Central Hudson suggests use of the 69% energy, 31% demand ratio that was proposed by Staff for the allocation of Power Purchase Agreement benefits related to Nine Mile Point Unit 2. MI seeks only equitable treatment for the larger customers it represents, saying that it could accept several different ratios based on a mix of factors including demand, volume and plant in service.

Discussion - We agree with the RD that the current economic circumstances constitute a 'rainy day' fully justifying the utilization of these funds to moderate rates, but we also agree with Staff that completely depleting ratepayers' 'savings' is not wise. Of the $43 million net credit available, we direct that $36 million be paid out as an EBC.

We also adopt Staff's proposal on phasing the credit and direct that it be paid out $20 million in the rate year, $10 million in the year ending June 30, 2011, and $6 million in the year ending June 30, 2012. This will provide the greatest benefit to ratepayers during the current economic downturn while moderating the impact of the credit's eventual expiration. The amounts specified for years two and three are subject to modification upon a showing of good cause in a subsequent rate filing or other petition to the Commission.

*20 On the issue of allocation, since the primary purpose of the EBC is to help offset the electric delivery

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rate increase, we approve the distribution of the credit in proportion to class responsibility for that increase as being a fair and sensible approach. The allocated credits will be refunded to customers on a kilowatt-hour or kilowatt basis, consistent with the manner in which each class is billed.

H. COST OF CAPITAL

1. Capital Structure.

[40] The RD found that Central Hudson's equity ratio was at the low end for companies with its A credit rating, and that growing interest rate spreads justified measures to maintain that rating. It, therefore, recommended moving the equity ratio to the higher of 47% or the Company's actual ratio as of the end of the first quarter of 2009, a compromise between the 46% conceded by Staff to be reasonable and the Company's requested 48%.

Both Staff and Central Hudson take exception to this recommendation, with the Company noting that it has, in fact, achieved an equity ratio of 48% as a result of an April 2009 capital infusion of $25 million from its parent company. Staff, while disagreeing with the 47% recommended by the RD, says that it is willing to accept the actual equity ratio of 46.68% (which it calculates using its capital structure methodology as updated to March 31, 2009).

Staff also argues, in effect, that it is not appropriate to accept the April equity infusion for purposes of calculating the Company's authorized rate of return without considering its full impact on Central Hudson's finances. It says that if Central Hudson's parent company financed this investment with debt, as Staff understands to be the case, a 'double leverage' situation will have been created which would justify an adjustment to the utility's required return on equity because of the lower debt-based cost of the new equity addition.

Discussion - The April infusion of equity by CHEG will not be considered. As Staff makes clear, this is not a simple question of recognizing the achievement of a 48% ratio. The manner in which the new equity was created could require a reevaluation of the Company's financial structure. Under the circumstances, including the fact that the Company has stated its intention to increase its equity ratio from 46% in September 2008 to 48%, we deny all exceptions and adopt the RD's recommendation. This result is consistent with the Company's gradually increasing its equity ratio without the use of an equity infusion potentially funded by debt, and provides a reasonable equity cushion given all of the aspects of our Order.

2. Return on Equity Generally

[41-46] The RD concluded a 10.05% return on equity (ROE) was appropriate, based on adopting Staff's methodology along with a capital structure adjustment to the ROE proposed by the Company. In addition, the RD stressed that it was more essential than ever to update the ROE methodology using the most recent data possible shortly before we make our decision in the rate proceeding. Central Hudson asserts that the RD should not have adopted any aspect of Staff's methodology for calculating return on equity because Staff failed to affirmatively support that methodology as required by our order in Con Edison. Staff responds that it devoted over forty pages in its initial brief to the explanation and support of its methods.

***21** *Discussion* - With the exception of the capital structure adjustment and the calculation of the risk-free rate in the Capital Asset Pricing Model (CAPM), we adopt the methodology used in the RD to calculate the allowed ROE. In addition, we have updated this methodology for data through May 2009. Our Con Edison Order stated that challenged practices must be supported with 'substantive reasons' provided 'on the record or in precedent cited in trial briefs.' [FN24] Staff has cited in its briefs to numerous cases in which we directly addressed the same methodological challenges made in this case, and explained our reasons for rejecting them. The exception is denied.

3. Return on Equity - Adjustment for Capital Structure

Central Hudson takes exception to the RD's reduction in

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the size of its proposed adjustment for differences between its equity ratio and the average equity ratio of the proxy group used in calculating ROE. It characterizes this as a 'contingent' exception that would not be raised if its request for a 48% equity ratio were granted.

Staff takes exception to the allowance of a capital structure adjustment of any size. It points out that the total risk of an investment, whether debt or equity, is the sum of business and financial risk. A higher equity ratio (all else being equal) means a lower financial risk. Therefore, a company with high business risk and a high equity ratio (low financial risk) might very well have the same credit rating and equity return as one with low business risk and a low equity ratio (high financial risk). Central Hudson's business risk, as reflected by its beta, was substantially lower than that of the proxy group. It would be expected, then, that the proxy group's average financial risk, would be lower (and its equity ratio higher). Consequently, Staff says, there is no reason to conclude that the difference in equity ratios between the proxy group and Central Hudson reflects a difference in total risk or expected return.

MI also takes exception to the adjustment for capital structure, contending that it is subsumed within the credit quality adjustment performed by Staff.

Discussion - We agree with the arguments presented by Staff and MI. Credit ratings reflect the rating agency's judgment of the total risk that will be incurred by a party who supplies capital to the rated business. Therefore, Staff's credit quality adjustment subsumes the financial risk represented by the Company's equity ratio adjustment, and we grant Staff's exception. This conclusion moots the Company's related exception concerning the relative weight accorded by the RD to the Company's equity ratio adjustment and Staff's credit quality adjustment.

4. Return on Equity - Credit Quality Adjustment

Central Hudson objects to the imputation of a credit quality adjustment. The RD found that Staff had made a credible argument that the proxy group used in determining the rate of return required by investors was riskier than Central Hudson and an adjustment to the Company's ROE was needed to reflect the lower risk of Central Hudson. As we recently discussed at length in the Con Edison Order, bond ratings are a way for investors to measure differences in risk. [FN25]Given that returns are a function of risk, it is logical that returns for companies with lower risk will be lower than for companies with higher risk. Further, it is reasonable to assume that such risk differentials would be magnified for equity holders. We therefore deny the Company's exception and adopt a 48 basis point credit quality adjustment.

5. Return on Equity - RDM Adjustment

*22 Central Hudson takes exception to the RD's adoption of a 10 basis point reduction in authorized return on equity proposed by Staff as a means of reflecting the lower risk of a revenue shortfall resulting from the adoption of RDMs. It contends that it is unfair to adjust for lower risk without also adjusting for higher risk that would be generated by other recommendations in the RD.

Staff responds that the recommended adjustment is necessary to reflect the fact that most of the companies in its proxy group do not have RDMs. The types of risk referred to by Central Hudson, by contrast, are common to all regulated utilities. Furthermore, Staff notes, the Company's own witness recognized that adoption of an RDM justified a reduction in return on equity to reflect lower business risk.

Discussion - Central Hudson cites no specific recommendations that would increase risk in a manner different from decisions that are commonly a part of the rate setting process. The risks associated with that process are common to both Central Hudson and the members of the proxy group used by Staff in determining ROE. An RDM, by contrast, marks a substantial departure from traditional utility cost recovery, and these mechanisms are not yet widespread among proxy group utilities. A separate adjustment to ROE is justified to reflect this difference. Accordingly, the Company's exception is denied.

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6. Return on Equity - Summary

As the RD stated, for nearly 15 years we have consistently employed an ROE methodology that gives the result of a two-state Discounted Cash Flow (DCF) model twice the weight of the results of the CAPM methodologies. Further, we have specifically rejected the Company's proposed Risk Premium method in several past cases. We find that our ROE methodology provides stable, reasonable results while relying primarily on directly observed investor behavior.

For the CAPM methodologies, we have used the latest three-month average of 10-and 30-year Treasury bonds to determine the risk-free rate. While Staff's methodology adopted by the RD used six months of data to determine the risk-free rate, in the recent Con Edison Order we expressed concern with using such a long period at this time and noted that a three-month average is consistent with the time period the Value Line data is derived from. [FN26]

We adopt the credit quality adjustment supported by Staff, as well as its RDM adjustment. We reject the Company's capital structure adjustment for the reasons discussed above.

We also reject any issuance expense adjustment, as we have repeatedly stated that such costs are only to be recovered if equity is expected to be issued during the rate year.

The result of our ROE methodology, as updated with data through May 2009, is 10.0%.

7. Cost of Debt

[47] The RD points out that there is agreement between the Company and Staff as to how to update the cost of debt estimate, as well as what debt costs should be reconciled. Both the Company and Staff request clarification that the Company will be permitted true-up and deferral of debt cost for both auction rate debt and new long-term debt issuances, rather than just auction rate debt as implied by the RD. That clarification is uncontested and is granted.

***23** As to the cost of debt to be employed, the Company stated in its Brief Opposing Exceptions that the estimated debt cost for future issuances should be increased to reflect adjustments due to a new issue premium and a liquidity premium. Staff, in its Brief Opposing Exceptions, also acknowledged such concerns and suggested that 100 basis points be added to future debt cost estimates to account for these adjustments. Because the costs will be reconciled, the actual debt costs the Company incurs will be recovered. The debt cost we estimate is used only to set rates.

We are estimating the cost of debt to be 4.86%, using the assumption that the October 2009 debt issuance planned will be issued at a rate of 7.15% (the recent average cost of debt rated A2 by Moody's Investors Service plus 100 basis points).

8. Overall Rate of Return

[48-51] Given the decisions we have made regarding the Company's capital structure, ROE, and debt cost rate, Central Hudson's overall after-tax rate of return will be as follows:

Component	Percentage	Cost Rate	Weighted Cost
Long-Term Debt	49.77%	4.86%	2.42%
5p Customer Deposits	0.91%	4.85%	0.04%
5p Preferred Stock	2.32%	5.05%	0.12%

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5p			
Common Equity	47.00%	10.00%	4.70%
5p			
Total	100.00%		7.28%

I. COST OF SERVICE, REVENUE ALLOCATION, RATE DESIGN AND RELATED MATTERS

I. Cost of Service

a. Allocation of Common Costs

[52-56] Both Central Hudson and Staff take exception to the RD's conclusion that 80% of the cost of functions common to both the electric and gas businesses be recovered in electric rates and 20% in gas rates - a significant change from the current 85%-15% split. The Company argues that the RD relied too heavily on quantitative measures and did not give sufficient weight to management judgment. It notes that the recommended change will shift approximately $2.9 million to gas rates; a shift that Staff says will increase gas rates by 6%. Staff and the Company both suggest that any change in the allocation ratio be phased in over several years. Staff adds that the quantitative factors used by the Company to estimate the appropriate ratio produce an 81.3%/18.7% split between electric and gas, and recommends that no more than a 1% movement toward that ratio be ordered in this case.

Discussion - We consistently endeavor to ensure that the rates paid by utility customers correctly reflect the costs incurred to serve them. If the quantitative measures cited by Staff are valid indicators of the appropriate ratio for allocation of common costs, it is clear that Central Hudson's rates currently incorporate a subsidy benefiting gas customers at the expense of electric.

We note, however, that a change in this allocation ratio is an extraordinary event. The record indicates that it has happened only once for Central Hudson in the last 15-plus years, and that revision was triggered by the very significant change in the make-up of the utility's business resulting from its divestiture of most of its generating plants.

*24 The quantitative factors used by the Company are proxies for, not direct measures of, the actual common costs incurred for the electric and gas businesses. Some judgment, as the Company argues, is needed in making a proper cost allocation. We do not feel that we are in a position to exercise that judgment on this record.

Accordingly, we direct that the existing allocation ratio be retained for the purpose of setting rates in this case, but we also find that the evidence clearly points to the need for a more thorough assessment of this issue in the future. Therefore, we direct that Central Hudson, in its next rate filing, provide an objective analysis of the relative responsibility of the gas and electric businesses for the costs of common functions. To the extent the Company believes that analysis should be tempered by management judgment, the basis for that judgment should be fully and clearly explained.

b. Classification of Gas Distribution Mains

Staff proposed to reclassify gas distribution main costs for purposes of the pro forma embedded cost of service study by assigning them entirely to the demand component of rates. Currently, based on the zero-intercept methodology that Central Hudson has used since at least 1990, those costs are classified 55% to the customer component of rates and only 45% to the demand component. Because gas mains constitute 20% of the total cost of gas service, the reclassification results in a very large shift in cost responsibility from residential customers to large gas users. The RD noted that both the existing and proposed methodologies are deemed acceptable by NARUC with no indication that one or the other is superior. It concluded that such a large shift in cost responsibility should not be adopted without compelling evidence that it is necessary to rectify some serious inequity.

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Staff takes exception to the recommendation against reclassification, suggesting that the RD did not give adequate weight to Staff's arguments demonstrating that mains costs are driven to a much greater extent by gas demand than by number of customers. MI and the Company support the RD's recommendation.

Discussion - Initially, we disagree with the implicit suggestion by the RD that the standard for changing a methodology that affects the allocation of cost responsibility among customers somehow becomes more difficult as the existing approach gains seniority. We have stated repeatedly that we strive to match cost responsibility with cost causation. Any showing that this objective is not being met is sufficient to warrant consideration of a change, even if it means abandoning long-held assumptions.

At the same time, as we discuss in connection with customer charges and the common cost allocation ratio, we have consistently taken a gradual approach when a sudden, full correction would create unacceptable bill impacts. That situation clearly exists here.

Finally, although we find the arguments persuasive as to the assignment of a greater proportion of gas mains costs to the demand component, we are not convinced on this record that *no* mains costs should be classified as customer related. Accordingly, we direct that for the purpose of setting rates in this case, the allocation of gas mains costs should be 65% demand and 35% customer. This is consistent with the ratio that we adopted for National Grid in approving a Joint Proposal in its recent gas rate case. [FN27]

c. Electric Pro Forma ECOS Study

*25 **[57, 58]** MI excepts to the RD's failure to require modifications to this study. It continues to object to the inclusion of commodity procurement costs and electric production costs in what is supposed to be a delivery cost study. It notes that the Company's witness agreed that neither production nor commodity procurement costs are required for delivery service. Furthermore, MI says, even if the inclusion of commodity procurement costs can be justified, they should not have been allocated volumetrically since the Company's ECOS witness acknowledged that they do not vary with volume.

Staff states in response that both the production and commodity procurement costs must be considered in developing the electric revenue requirement. It notes that the same methodology was used for the ECOS study in the Company's last rate case.

Discussion - MI's exception is granted as to the allocation of procurement costs, and Central Hudson is directed to redo its *pro forma* study using an allocator appropriate for labor costs that do not vary with volume. Allocation of procurement costs to SC13 customers, and then unbundling them to the Merchant Function Charge, is appropriate in light of the Company's continuing POLR function. Doing so volumetrically, however, improperly shifts apparent cost responsibility toward large customers, generating an unreasonably low *pro forma* rate of return for the SC13 class.

As stated in the RD, the inclusion of certain generation costs in delivery rates was previously approved by us and MI's exceptions concerning these costs are denied.

d. Electric Delivery-Only ECOS

[59] Staff takes exception to the RD's failure to recommend that Central Hudson be required to submit a delivery-only historic embedded cost of service study with its next rate filing. It notes that the Company has indicated its willingness to do so, with certain caveats. Central Hudson says that it will have to make certain simplifying assumptions in order to segregate commodity-related costs, and it does not want to be bound to vouch for the accuracy of the results.

Discussion - Staff believes that a delivery-only historic embedded cost of service study will facilitate comparison with the *pro forma* study, making it possible to identify where changes are occurring. We agree that the capability to better understand variations in costs across time periods, is valuable and we grant Staff's exception. The Company will be required to submit the requested study with its next rate filing, but it will be free to state

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its disagreement with any results it considers to be incorrect or misleading.

e. Gas Marginal Cost of Service Study

[60] Staff recommended that the Company be required to include a marginal cost of service study with its next gas rate filing, and repeated this request in its Brief on Exceptions. The issue was not contested or briefed and was not addressed in the RD. In its Brief Opposing Exceptions, Central Hudson questions whether there is a functional need for such a study, and adds that if one is required, it will need adequate time to collect the required data, perform the analysis, and prepare the documentation.

***26** *Discussion* - As Staff noted, a marginal cost study remains necessary to ensure that tail block rates are set appropriately. Central Hudson's next gas rate filing should include such a study. If the Company believes it has not had adequate time to complete a study by the time of the filing, it should explain why that is the case and propose a schedule for completion.

f. Gas Service Classification No. 11 (SC11).

(1) Crow's Nest Brook and Orr's Mill Road Regulator Stations

[61] The RD requested comments on DOD/FEA's assertion that all system customers should share the cost of these regulator stations. Currently, 89% of the cost of Crow's Nest Brook and 100% of the cost of Orr's Mill Road are allocated to Service Class 11 DLM, the U.S. Military Academy at West Point.

Staff responds that it is unsure how the stations benefit all customers and, therefore, cannot address the allocation of costs. Central Hudson says that the Orr's Mill Road station is used only for service to West Point, while the costs of the Crow's Nest Brook station are allocated between West Point and the service classes of downstream customers in proportion to their usage.

Discussion - No good basis has been presented for upsetting the Company's allocation of costs for these facilities. Responsibility is currently borne by the customers that use them in proportion to their usage.

(2) Cost of Meters

[62] Usage by West Point is measured by taking the difference between upstream and downstream meters on each of the lines serving the facility. The Company allocates the full cost of the meters to West Point. The RD found that some portion of the cost of downstream meters should be allocated to downstream customers, and asked for comment on an appropriate ratio.

Central Hudson excepts, saying that the individual meters of downstream customers cannot all be read simultaneously, which would be necessary to 'back out' West Point usage if the downstream meters were not in place. Staff stated that it did not except to the RD's recommendation, but had no comment on how to allocate the costs. DOD/FEA initially deferred to the other parties for a determination, but in its Brief Opposing Exceptions it asserted that the meters should be charged to the customer classes represented by the downstream customers.

Discussion - The downstream meters would not be needed if there were no downstream customers, and they would not be needed if there were no West Point. Since both customer groups do exist, the cost of these meters should be allocated between them on the same basis as the regulator stations discussed above; that is, in proportion to the customers' usage of the lines on which the meters are located.

(3) Certification Requirement for SC11 DLM

Central Hudson excepts to the RD's requirement that the Company certify in its next rate filing that its allocation of costs to the SC11 DLM class does not include the cost of mains smaller than 6 inches. The Company says it was not required to adhere to this mains allocation limitation beyond the term of its last negotiated rate plan, and that it agreed to the allocation in this case because of the facts, not because of an obligation.

***27** DOD/FEA's response recognizes that Central Hud-

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son can propose changes in its allocation of costs to the SC11 DLM class, but notes that the allocation of the costs of smaller mains included in Central Hudson's initial filing in this case would have been costly to West Point and could easily have been overlooked. It asks that proposed changes in future rate cases be clearly identified.

Discussion - DOD/FEA's request is reasonable. Central Hudson's exception is granted as to the requirement for adherence to the cost allocation formula currently in place, but the Company is directed to ensure that any change in the allocation of mains to the SC11 DLM class proposed in a future rate filing is clearly flagged.

2. Revenue Allocation

a. Electric Revenue Allocation

[63, 64] Staff excepts to the RD's conclusion that Staff's proposed 2.18 times system average constraint on rate increases for the SC2-Non-Demand, SC5 Area Lighting, SC13 Substation and SC13 Transmission classes is unreasonable. It notes that very large interclass subsidies currently exist in favor of these classes; says that it is appropriate to consider commodity prices in evaluating the impact of higher delivery rates; argues that accrued power purchase benefits inuring to these customers should be considered; and contends that large dollar increases in customer bills can be ignored if they represent small percentage increases. Finally, Staff says that if the RD's statement 'that everyone should share the pain equally and that disproportionate rate shocks should be avoided' means that ECOS studies should be ignored, it objects.

MI argues that now is not the time to impose major increases on SC13 customers. It recommends that the constraint be set in the range of 1.20 to 1.25 as was recommended by the RD for gas.

In its Brief Opposing Exceptions, Staff says that given the likely size of the rate increase, it would now agree to lower and upper constraints of 75% and 125%.

Discussion - The RD recommended that a final determination of appropriate constraints should await a re-run of the ECOS study which the Company was to provide with its Brief on Exceptions. That study shows that the ratio of the SC13 rate of return to the system average return has improved from -1.19 to - 0.58. This, combined with the size of the increase we are authorizing, suggests that a lower allocation constraint is appropriate. We direct that a constraint of 1.25 times the system average increase be used. This is within the range supported by MI and is acceptable to DPS Staff.

b. Gas Revenue Allocation

[65] The RD recommended a sliding scale for the upper constraint on allocation of a gas rate increase among service classes, varying from 120% to 150% in inverse proportion to the size of the overall rate increase. MI argues that current difficult economic conditions dictate that a 120% constraint be applied. No other party comments.

Discussion - Because of the size of the rate increase we are authorizing, the RD's proposed formula is moot and the 120% constraint will be adopted.

3. Rate Design

a. Customer Charges

***28 [66, 67]** No party disputes the finding that Central Hudson's embedded cost of service studies indicate the customer charge components of the Company's gas and electric rates do not reflect the full amount of the customer-related costs incurred by the utility in providing delivery service. There is, however, a difference of opinion as to how far toward the cost-based rates suggested by those studies the current charges should be moved.

The RD recommended adoption of the increases proposed by the Company. For most residential customers, this would raise the customer charge for electric service by $9.00 per month, and for gas service by $7.00.

Staff takes exception to this recommendation, arguing

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that the customer charge for residential customers should be increased by only $2.00 for electric service and $3.00 for gas. It points out that while we have recognized the desirability of moving these charges toward the levels indicated by the embedded cost of service studies, we have consistently followed a policy of moving gradually in that direction in order to avoid adverse bill impacts for low-usage customers. This policy, it says, is well illustrated by the fact that we have raised the customer charge for residential electric customers by more than $2.00 only once since 1996.

Discussion - Staff's explanation of our policy with regard to the gradual alignment of customer charges with customer costs for the residential service classes is accurate, and we are not persuaded that any good reason for deviating from it has been shown. Therefore, we adopt Staff's position as to the increases for these classes.

The customer charge increases proposed by Central Hudson for commercial and industrial customers do not present similar bill impact concerns. We note, in fact, that MI supports the Company's position as to the classes under which most large gas and electric customers take service. Accordingly, we adopt Central Hudson's proposed charges for the non-residential classes.

b. Maximum Daily Quantity (MDQ) for SC11

[68] Gas customers receiving firm transportation service under Central Hudson's SC11 are billed based on their MDQs which are set forth in their service agreements. If a customer's usage during the winter exceeds its MDQ on five or more days, the MDQ is automatically reset on April 1 to the average of the five highest usage days experienced.

The RD recommended adoption of a proposal proffered by the witness for DOD/FEA and supported by Multiple Intervenors that would require MDQs for SC11 customers to be automatically adjusted downward as well as upward based on peak winter usage. It made that recommendation despite finding that the proposal might be risky for customers, because the affected customers supported the change and neither Staff nor the Company objected.

The RD also suggested that the proposal might not be necessary because customers should be able to request changes to their MDQs as part of the annual renewal process for their service agreements. It noted further that the MDQ is an absolute limit, regardless of weather, so that excess usage clearly indicates the need for an increase. The same cannot be said about reduced usage which may simply result from warmer weather. The RD asked the parties to comment further on these points in their briefs on exceptions.

***29** The Company responds that its failure to address the proposal was an oversight. It argues that the tariff change could allow SC11 customers to avoid cost responsibility to the detriment of others on the system. Staff agrees with the RD's suggestion that existing tariff provisions are adequate to allow for MDQ adjustment as necessary. MI, in contrast, says it knows of no tariff provision allowing for adjustment of the MDQ, and continues to support the change.

Discussion - We will not require the requested change to Central Hudson's SC11 tariff. As the RD noted, repeated excess usage is proof that the MDQ is too low, but the converse is not true. Reduced peak usage in any given year may say little about peak requirements generally. Customers should bear the cost of the capacity required to deliver their expected maximum usage even if that peak is not reached in some years.

Customers should, however, have the ability to conform their MDQs to their actual requirements. We clarify, therefore, that customers have the right, by notice given as required by the tariff, to request a change in MDQ at the annual renewal of their service agreements. Requested reductions supported by objectively verifiable information should not be unreasonably denied by the Company.

4. Retail Access Lost Revenue Mechanisms

a. Gas

[69, 70] Lost revenues associated with Central Hudson's

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gas retail access program are currently recovered from ratepayers in two pieces. Fifty percent is collected through the Supply Charge component of the Merchant Function Charge (MFC), which is avoided by retail access customers, and 50% through the transition adjustment paid by all customers. The RD recommended that this mechanism be continued.

Staff takes exception. It supports 100% recovery through the transition charge, arguing that our policy statement on unbundling concluded that some supply-related costs were related to the utility's provider of last resort (POLR) function and should be recovered from all customers; [FN28] that the basis for adoption of a 50/50 split in the Company's last rate settlement is unstated; and that we have said that the parties are free to propose different splits in individual rate cases.

Discussion - We agree with the RD's conclusion that the current 50/50 split between the MFC and the transition charge for recovery of retail access lost revenues is a reasonable compromise, giving some benefit to retail access customers without absolving them completely of responsibility for funding POLR-related costs. Staff is correct in noting that we left open the possibility that this sharing ratio could be changed in future rate cases, but that change should not be merely another assumption. It should be supported by a new consensus of the interested parties, or by substantive analysis which the RD found to be lacking in this case. The exception is denied.

b. Electric

[71, 72] Pursuant to the procedures defined in Central Hudson's last rate order, fifty percent of forecast retail access lost revenue is recovered by adding a separate component to the MFC Supply Charge on an MFC group-specific basis. The remaining fifty percent is recovered through the MFC group-specific Transition Adjustment. At the end of each rate period, a reconciliation is performed between the actual retail access-related lost revenue and the amount of retail access-related lost revenue recovered from ratepayers.

*30 The RD recommended that the current mechanism be continued. Staff takes exception. It continues to support including 100% of forecast lost revenue in delivery rates, in part because of concerns regarding potential conflicts that might result from the tandem operation of the current mechanism and the RDM which we are adopting in this order.

SCMC and MI oppose Staff's exception. MI notes that the need to design a collection mechanism that works with an RDM does not mean that the methodology for allocating cost responsibility among customer groups has to be changed. It says that Staff's proposal simply amounts to a reversal of years of effort to achieve the unbundling of commodity and delivery rates.

Discussion - For the reasons stated in the RD, we will not modify the current allocation of cost responsibility for forecast retail access lost revenues, or require that recovery be included in base rates. Staff's exception to the RD's recommendations on these points is denied. At the same time, however, we agree with Staff that modifications to the lost revenue recovery mechanism will be required to avoid certain unintended interactions with the RDM we are adopting in this case.

Currently, Central Hudson's MFCs, MFC-related lost revenue recovery, and Transition Adjustment charges are calculated and accomplished within each of four MFC groupings. The RDM, by contrast, must be class specific and will reconcile each class's actual total delivery revenue (inclusive of MFC revenues) to our approved delivery revenue forecast. The concerns expressed by Staff concerning the interaction of these two mechanisms include over or under recovery of retail access lost revenues and the potential for interclass revenue transfers resulting from interaction between the class-specific RDM and the group-specific MFC.

To address these concerns we will require that MFCs and Transition Adjustment Charges be calculated and applied on a class and sub-class specific basis, thus eliminating the transference of cost responsibility between classes and sub-classes within each MFC group. Further, we will require that the final reconciliation performed as part of the retail access lost revenue

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recovery mechanism be discontinued for classes subject to an RDM (the RDM will provide the final reconciliation) and that it be on a class and sub-class specific basis for classes and sub-classes not subject to the RDM. Finally, MFC and Transition Adjustment Charges are to be included in the RDM targets. These three steps will ensure that the two mechanisms do not conflict and thus potentially result in over or under recovery of MFC revenues.

5. Factors of Adjustment

a. Electric

[73, 74] The RD recommended that voltage-specific factors of adjustment be implemented by Central Hudson. No party takes exception to this recommendation, but Staff reports that it has conferred with the Company and determined that the factors cannot be in place until August 1, 2009. MI, the principal proponent of this change, does not object to the one-month delay. We accept the proposed August 1, 2009, implementation date.

b. Gas

***31** Central Hudson says that the RD correctly stated the standard for establishing LAUF targets, but failed to address the application of those targets in making the annual reconciliation. Inasmuch as Staff has agreed that the same methodology used in setting targets should be used for the annual reconciliations, and no other party objects, we grant the requested clarification.

6. Allocation of Power Purchase Agreement (PPA) Benefits.

[75, 76] Currently, the net benefits realized by Central Hudson from its below-market power purchase contract with the owners of the Nine Mile Point Unit No. 2 (NMP2) nuclear plant are flowed through the Company's Purchased Power Adjustment factor in its Electric Cost Adjustment Mechanism and allocated among the service classes and sub-classes on the basis of kWh sales. Staff proposed instead that only 69% of the benefits be allocated based on energy, with the remaining 31% based on peak demand. This, it said, would better reflect the manner in which the capital costs associated with NMP2 were recovered from customers between 1988 and 2001.

The RD recommended that Staff's position be adopted, and MI takes exception. MI repeats arguments previously made in its trial briefs that the present allocation reflects one of a number of interrelated compromises incorporated in a broader settlement that should not be undone, and that reducing benefits flowing to large business customers in these difficult economic times is not a good idea.

Discussion - The PPA benefits in question resulted from Central Hudson's sale of its interest in NMP2, and it is appropriate that they be allocated in proportion to the contribution of each customer class to the utility's cost of acquiring of that interest. We concur with the RD's conclusion that Staff's proposal creates a better match between that past capital cost responsibility and the receipt of the benefits now flowing from that facility. While we appreciate that the current economic circumstances are difficult for large customers, that difficulty extends to all customer classes. MI's exception is denied.

J. SAFETY AND RELIABILITY PERFORMANCE MECHANISMS

1. Electric Reliability Performance Mechanism (ERPM)

[77-79] There were no exceptions to the RD's principal recommendation that the Company's ERPM should continue with the same targets and associated negative revenue adjustments for the System Average Interruption Duration Index and the Customer Average Interruption Duration Index. There was also agreement on two project-specific targets, namely energizing the proposed Galesville substation, and completion of 150 miles of enhanced distribution main line tree clearance. There were, however, several exceptions and requests for clarification concerning the details of the mechanism.

a. Project Targets

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The RD approved the use of two project targets 'with a 5 basis point revenue adjustment dependent on the completion of each during the rate year.' [FN29] Staff asks that we clarify that there will be a separate five basis point adjustment associated with each project. We grant the clarification.

b. Annual Compliance Reports

*32 The RD endorsed a requirement for annual reports due on March 31. Staff takes exception, pointing out that it recommended separate reports due on March 31 for the index targets and on August 1 for project targets. Central Hudson objects to the additional reporting requirement.

Discussion - Staff's representation indicates that the two reports are distinct and non-duplicative. On that basis, splitting the reporting in two should not add unnecessary cost. Staff's exception is granted.

c. Continuation

Staff takes exception to the RD's conclusion that Staff should not be permitted to unilaterally adopt new project targets each year during a continuation of the ERPM between rate cases. As a compromise it suggests that the Enhanced Tree Trimming Program, which is ongoing, continue to be a target, and that the second target be selected by consensus between Staff and the Company. If no consensus is reached, the full 10 basis point adjustment applicable to the project portion of the ERPM would be assigned to the tree-trimming program.

In response, Central Hudson says it is willing to collaborate on new project targets, and suggests that this take place during the quarterly meetings it has customarily had with Staff.

Discussion - Staff's proposal is a reasonable compromise and is adopted as a means of establishing new project targets after the rate year. The Company's suggestion that the collaboration take place during regular quarterly meetings is also a good one. No party took exception to the RD's finding that those meetings have been valuable and that they should not be eliminated if Staff resources are sufficient to accommodate them.

d. Future Rate Cases

The RD found that requiring the Company to propose an ERPM every time it files a rate case is unnecessary because the continuation clause ensures that silence is the equivalent of consent to the existing mechanism. Staff responds that utilities sometimes propose ERPM modifications later in the rate case process, putting the other parties at a disadvantage. It asks that the Company be required in its original filing to either accept continuation of the ERPM or propose a new one.

Central Hudson says the requirement is unnecessary because silence in the original filing is sufficient.

Discussion - Staff's request is not burdensome and is consistent with our concern that original filings be complete and informative. Staff's exception is granted.

2. Service Quality Performance Mechanism (SQPM) - PSCComplaint Rate

Staff takes exception to the RD's recommendation that both the threshold complaint rate and the associated negative revenue adjustment (NRA) be kept at their current levels. It says that the existing threshold was, of necessity, only an estimate when it was set two years ago at the inception of Central Hudson's SQPM. Now that there is some history on which to base the target, leaving it far above the level of actual performance would make it ineffective. Staff also says that the NRA for Central Hudson is lower than that for all but one other utility as a percentage of common equity and should be raised to have the requisite deterrent effect.

*33 *Discussion* - We understand the RD's concern that setting stricter targets in response to good performance could be perceived as punishing success, but that is not the situation here. This case is our first opportunity to establish a target for Central Hudson that reflects actual experience in the service territory. Moreover, the target of 1.7 complaints per 100,000 customers recommended by Staff is more than double the Company's recent ex-

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perience and could hardly be considered burdensome. The fact that the target for a neighboring utility is higher is simply not relevant. We have always established targets on a utility-specific basis in recognition of differences among service territories that are unrelated to the quality of service provided.

Finally, we agree that the impact of potential negative revenue adjustments on earnings should be of a similar magnitude for all utilities. Accordingly, we grant Staff's exceptions.

3. Gas Safety Performance Mechanism (GSPM) - Negative Revenue Adjustments

[80, 81] The RD found that the size of the increase in NRAs associated with GSPM targets had not been adequately supported by Staff, and recommended that the increase be held to the rate of inflation. Staff takes exception, pointing to testimony in which it stated that the total NRA of 30 basis points it proposes is the minimum level of total regulatory liability adopted by the Commission in gas rates cases since 2005, a period that covers decisions for at least five utilities.

Discussion - Staff is correct and its exception is granted. It is our intention that the impact on earnings of failures to meet safety targets be equivalent across utilities. Staff's recommended NRAs in this case accomplish that objective.

4. GSPM - Gas Leak Repair Targets

[82, 83] The RD found that combining a leak backlog target with funding for a discrete number of leak repairs at a time when the number of leaks discovered is increasing is both unfair to the Company and bad policy, particularly since the Commission has previously declined to allow deferral accounting for excess repairs. Therefore, it recommended a 'leaks repaired' target with deferral accounting authorized for the cost of repairs made beyond the target number.

Staff excepts saying that with a leaks repaired target, the backlog can increase, perhaps significantly. Safety concerns require that a backlog target be established to ensure that the Company will reduce the number of unrepaired leaks to a specified minimum level. Staff also opposes advance authorization for deferral of any excess gas leak repair expense the Company might experience during the rate year.

Discussion - Our previous disallowance of a request by Central Hudson for authorization to defer excess costs incurred for gas leak repairs came in the context of the Company's current rate plan. That plan was the product of negotiations. Inherent in such negotiations is a give and take through which a party may be persuaded to accept a sub-optimal result on one issue in order to secure a better than hoped for outcome on another. Central Hudson agreed to a budget for gas leak repairs that would remain fixed for the duration of its rate plan, and we assume it did so with full awareness of the risk involved.

***34** The same reasoning does not apply going forward from this case. We are providing Central Hudson with a rate allowance that it says will be sufficient to permit it to repair 627 leaks. If it is required to repair substantially more leaks than that in order to meet a backlog target, it will necessarily have done more *work* than was contemplated by this rate order. If it also incurs more *cost*, and it can present a petition that meets the three prongs of our test, Central Hudson is free to seek deferral authorization for the excess amount expended. This resolves the potential 'Catch 22' described in the RD where the Company would have to choose between overspending its budget without hope of reimbursement, or incur an NRA for not meeting the backlog goal.

Accordingly, we grant Staff's exception and adopt its proposed targets of 350 leaks for the total backlog, and 30 leaks for the repairable leak backlog.

5. GSPM - Additional Issues

Staff's testimony included unopposed recommendations that all safety-related programs be continued until changed by the Commission, and that Central Hudson be required to report to the Director of our Office of Gas, Electricity and Water annually concerning its per-

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formance on all GSPM targets. Neither proposal was addressed directly in the RD. We agree that both should be approved as presented.

K. REVENUE DECOUPLING MECHANISMS

1. Reconciliation and Carrying Charges

[84-94] Under the RDM proposals presented in this case by both Staff and the Company, variances between forecast and actual revenues will be calculated monthly, accumulated amounts will be reconciled annually, and the balances will be either surcharged or refunded to customers, with carrying charges. The RD recommended that for both mechanisms, reconciliations should be monthly, and carrying charges should be calculated at the Company's pre-tax rate of return.

Staff takes exception to both recommendations. As to the gas RDM, it suggests that frequent reconciliation is unnecessary because the weather normalization clause will account for most of the short-term variance in revenues. For the electric RDM, it suggests the use of a 'circuit breaker' that would trigger reconciliation if the accumulated RDM adjustments exceeded $4 million.

For both mechanisms, Staff argues that carrying charges should accrue at the other customer capital rate. It says this lower rate is justified because there is little or no risk associated with the recovery of any amount, which is guaranteed, and because the rate is applied symmetrically both to amounts owed by, and owed to, the Company.

Central Hudson responds with respect to the reconciliation periods that Staff has failed to demonstrate any error in the RD. It also argues that the purpose of the carrying charge is to maintain the economic value of any accumulated balance. The appropriate rate, it contends, is one that reflects the time value of money to the party to whom it is owed. For the Company, that is the pre-tax rate of return.

*35 *Discussion* - We grant Staff's exceptions. Monthly reconciliation will needlessly complicate the operation of the RDMs without providing any greater degree of financial protection to the Company or to customers. Instead, we accept Staff's proposal of a $4 million reconciliation circuit breaker for the electric RDM, and we also adopt a $2 million circuit breaker for the gas RDM. The application of a weather normalization clause and the availability of the circuit breaker should prevent excessive amounts from accumulating either for credit or surcharge. This renders immaterial any risk to the economic value of sums owed to the Company through operation of the RDMs, and makes the other customer capital rate appropriate for carrying charges on accumulated balances. In addition, the use of the other customer capital rate is consistent with our past treatment of carrying charges where the amount is unknown and will be recovered over a relatively short period.

2. Electric RDM - Model

Staff excepts to the RD's recommendation that a Unit per Customer (UPC) model be used for the electric RDM rather than a Revenue-per-Class (RPM) model. It contends that the UPC model would inappropriately allow the Company to retain the incremental net margin generated by the addition of new customers. Relying on regulatory lag to resolve this revenue disparity as suggested by the RD is inadequate, Staff says, because an RDM protects the Company against the kind of loss of revenue that might trigger the rate filing that is necessary before ratepayers can realize any benefit from customer growth. Staff differentiates the gas and electric businesses, finding the UPC model acceptable for gas utilities which continue to need an incentive to add load, while electric utilities, with nearly 100% customer penetration, do not. Finally, Staff argues that consistency of RDM design among utilities is not an arbitrary choice but rather an avoidance of duplicative effort.

Central Hudson responds that Staff's position would effectively put a 'hard cap' on electric revenues, creating exactly the type of disincentive to support energy efficiency that the RDM is intended to eliminate. It says Staff relies excessively on previously decided cases and that the RD was correct in calling for greater experimentation.

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Discussion - Staff is fully justified in relying on our previous conclusions concerning the appropriate form of an RDM for electric utilities. We expended a great deal of effort in previous cases addressing precisely the types of issues presented here. Until we are presented with persuasive evidence that a change should be made, we will continue to require the adoption of a Revenue per Class model for revenue decoupling mechanisms applicable to electric utilities. Staff's exception is granted.

3. Electric RDM - Exemptions

The RD recommended that SC3 be exempted from the electric RDM because there are no energy efficiency programs proposed for this class. Staff takes exception saying that even though there are no specific programs identified, Central Hudson's sales forecast attributes sales declines to the Energy Efficiency Portfolio Standard (EEPS).

***36** MI opposes Staff's exception citing the Company's own statements that it has no energy efficiency programs planned for SC3 customers. Central Hudson did not oppose the RD's recommendation to exempt the class.

Discussion - The purpose of an RDM is to remove utility disincentives to promote energy efficiency programs, not to shift all risk of declining revenue to ratepayers. Central Hudson has no EEPS programs to promote for SC3 customers, so there is no reason to include the class in the RDM. Staff's exception is denied.

L. HOURLY PRICING PROGRAM

1. Expansion of Hourly Pricing Program (HPP)

[95, 96] The RD recommended approval of Staff's proposal to lower the threshold for Central Hudson's current HPP to encompass customers with 500 kW or more of demand. The Company takes exception. It says Staff was required to prove that the program was justified for Central Hudson's specific territory and customers, not just consistent with Commission policy generally. It adds that the RD was inconsistent in imposing these burdensome requirements on customers in bad economic times, and that the timeline proposed by Staff for implementation was excessively compressed.

Staff responds that it justified its proposal based on the benefits found by the Commission to be inherent in an HPP, that there was no showing that customers lack the capability to adapt to the program, and that the implementation schedule it proposed allowed significantly more time than was required by National Grid for a much larger effort.

Discussion - The exception is denied. As the RD noted, we have approved expansion of the mandatory hourly pricing program to include customers of this size for other utilities. Absent a showing of unique circumstances on the Central Hudson system that would render our generic conclusions inapplicable, Staff was not required to prove that benefits we have previously found to exist on a statewide basis will also be realized for Central Hudson.

The schedule and outreach efforts proposed for implementation of the program expansion appear reasonable in light of similar expansions on other utilities. Furthermore, we are adopting the RD's recommendation, to which no party took exception, that affected customers be served with, and given an opportunity to comment on, Central Hudson's implementation plan when it is submitted to us. This will provide an additional opportunity to refine the implementation effort, if necessary, to meet any specific concerns that may be brought to our attention by those customers.

2. Hourly Pricing Program - Generation Capacity Cost.

[97, 98] The RD concluded that both the current volumetric allocation of UCAP costs and Staff's proposed allocation based on contribution to system peak demand were inappropriate. It recommended that the current method be retained, but that Staff and the Company explore alternative demand-based options for the next rate filing.

Staff took exception to this recommendation saying that its proposal correctly matches cost causation and re-

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sponsibility. It disagrees with the RD's finding that average demand might be a better allocation factor than peak because the only successful strategy for customers under Staff's proposal would be to reduce average demand. It also notes that we have found significant benefits to be derived from reducing system peak demand and that measures which force customers to try to do so should be encouraged.

*37 *Discussion* - A key to the provision of just and reasonable rates is reliability, and a key prerequisite for the provision of reliable service is the presence of an adequate amount of generation capacity. New York has had an installed generation capacity requirement for many years, long pre-dating electric restructuring. While the Company and the RD are correct that adequate generation capacity is needed 12 months a year, it is clear that the threat of shortage is highest and the need for generation capacity greatest during the peak and near-peak hours of the summer months.

Accordingly, we direct that Central Hudson adopt the Staff proposal for basing the generation capacity charge on each customer's demand during the NYISO peak hour. In contrast to Central Hudson's current generation capacity charge, the Staff proposal will send a strong price signal that will focus customers' attention on the high load hours that correspond to severe summer heat waves, which are the hours during which demand reductions benefit the State's electric system the most.

Central Hudson's current approach spreads the price signal to all 8760 hours of the year. Clearly, as for nighttime and weekend hours, this approach is inadequate, and needs to be improved. We disagree with the Company's assertion that basing the charge on the peak hour is unfairly generous to customers whose individual peaks occur in winter months. The payments made by the Company for generation capacity are tied, by the NYISO's FERC- approved tariff, to the NYISO system's peak hour; since the system peak hour only occurs in a summer month, customers' use in non-summer months costs the Company nothing in terms of its payments to the NYISO for generation capacity. Proper application of the principle of cost causation, therefore, yields a rate design which, like the Staff proposal, charges customers nothing for generation capacity cost associated with non-summer usage.

The RD noted that if all customers are somehow successful in forecasting when the critical peak hour will occur, they will reduce their consumption, and the anticipated peak will not occur, shifting the peak to some other day and hour. This contributed to the RD's rejection of the Staff approach. We do not share that concern. What it does show is that, under the Staff's approach, customers will need to acknowledge that they face a potentially high price in any summer hour in which there is a significant probability that a system peak will occur. This acknowledgment effectively spreads the generation capacity price signal received by customers beyond a single hour. In practice, this effect gives customers a signal to cut back during the afternoon hours of all summer heat waves. Such a price signal is a vast improvement over Central Hudson's current, excessively diluted approach.

We are concerned, however, about the timing of the implementation of the Staff proposal which would have the new pricing begin in May 2010. Because of a lag inherent in the NYISO's generation capacity pricing rules, this would make each customer's contribution to the NYISO's 2009 summer peak crucial. Given that the summer of 2009 is already underway, customers would not have time to understand their new generation capacity charge in time to react to a July or even August peak, and certainly not to a June peak. Accordingly, we direct that the existing rate remain in effect for an additional year, with the Staff proposal going into effect in time to be applied to each customer's contribution to the system's 2010 summer peak. This delay is unavoidable, given the current date, and it will give the Company ample time to inform customers of the new rate.

M. OTHER ISSUES

1. Low Income Programs

*38 [99] The RD recommended that the level of funding proposed by Staff for low income programs, approximately $1.8 million, be approved, but that the full amount

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be used for expansion of Central Hudson's Enhanced Powerful Opportunities Program (EPOP). Staff had proposed using about $500,000 of the total to implement a monthly bill discount for customers receiving assistance through the Home Energy Assistance Program (HEAP). The RD reasoned that the funds would be better applied, from the standpoint of all ratepayers, if used to provide relief to customers who were in arrears in their payments, a condition of eligibility for EPOP.

Although no party takes exception to the RD's recommendations, Staff expresses strong disagreement with certain aspects of the reasoning underlying them. It argues that broad-based discount programs play an important role in a comprehensive low income program because they address the needs of customers who may be able to pay their utility bills, but only by diverting funds from other basic needs such as food and clothing. In fact, Staff argues, aiding only customers in arrears may perversely promote the ignoring of utility bills in favor of other expenses for which no assistance similar to EPOP is available. Finally, Staff says, whether low income customers are helped, rather than whether all ratepayers benefit, should be the primary consideration in the design of these programs.

Discussion - While Staff states that it is willing to accept the RD's recommendations, its comments make it clear that it continues to support the adoption of a bill discount, and we find its arguments to be persuasive. A low income program should not only provide assistance to customers who have been unable to pay their bills; it should also help those who are sacrificing to keep their payments current.

Elsewhere in this order, we approve increases in the customer charges for gas and electric service. These charges are particularly burdensome to low income customers because they are unrelated to usage and cannot be avoided. Therefore, we will modify the RD's recommendation by directing that the $500,000 increase in the rate allowance for low income programs be used to fund a monthly discount of $5.00 for customers on whose behalf Central Hudson receives a HEAP payment. As is currently the case with the EPOP program, to the extent that the actual cost of the discount program varies from the authorized expenditure level, any excess costs incurred by the Company will be deferred for future recovery up to 15% of the program budget, and any under expenditures will be rolled over for program use in subsequent years.

2. Weather Normalization Clause (WNC)

[100] Due to an ambiguity in the language of the RD, Central Hudson requests clarification that the recommended WNC will apply only from October 1 through May 31, as on other gas systems in the State.

Staff takes exception to the RD's recommendation that the RDM and WNC adjustments be combined in a single line item on customer bills, suggesting that doing so will needlessly complicate reconciliation of the two.

***39** *Discussion* - The Company's requested clarification is granted. We also clarify, in response to Staff's concern, that the RDM and WNC adjustments are to be combined solely for the purpose of presenting a single number on customer bills. Otherwise, the adjustments are to be separately calculated and recorded by the Company and clearly broken out in any reports required by Staff for the purpose of auditing reconciliations.

3. Property Transfer

[101] The RD recommended approval of an uncontested transfer of certain real property held by Central Hudson from a rate base account to a non-utility property account, with the net appraised value of the property to be deferred for ratepayer benefit. Staff seeks clarification that Central Hudson's erroneous filing of this accounting change as a request for approval of a transfer pursuant to PSL §70 does not relieve the Company of the obligation to make a §70 filing when it decides to sell the property to a third party.

Central Hudson responds that it has expressed its willingness to agree to a six-month holding period before it can transfer the property to a third party. This, it says, will ensure that the property is not 'flipped' for a profit that should have belonged to ratepayers. If it is sold

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after that period, no §70 proceeding should be required.

Discussion - There is no magic to a six-month holding period that would convert the loss of a benefit to ratepayers into a matter of no concern to us. The issue would remain as to whether ratepayers received fair value for property they originally financed through their rates. A §70 filing need not be complex or burdensome and it will be required if and when this property is to be transferred.

III. UPDATES

With its Brief on Exceptions, Central Hudson provided numerous updates to previously submitted data. In general, these were authorized, are unobjectionable and are adopted. Staff, however, raised questions about a few of the updates in its Brief Opposing Exceptions. Those presenting issues requiring our decision have been addressed elsewhere in this order. The remainder, consisting of undisputed corrections or modifications, and revisions required for certain items because the numbers from which they are derived have been updated (*e.g.*, the productivity adjustment, the allowance for payroll taxes, and I&IA expense) have been accepted and incorporated in our calculations.

VI. PETITION FOR DEFERRAL OF STORM RESTORATION COSTS

[102] As we noted above, Central Hudson submitted a petition on January 2, 2009, requesting authorization to defer approximately $3.3 million in incremental storm restoration costs associated with a December 11, 2008, ice storm. We initiated Case 09-M-0004 to consider the petition, and notice of its pendency was published in the New York State Register on February 18, 2009, as required by the State Administrative Procedure Act. No comments in response to the notice were received.

***40** In its Brief Opposing Exceptions, Staff reported that it had fully reviewed the facts underlying the Company's petition and had determined that they met the requirements of our three-prong test for deferral authorization. [FN30]After notifying the active parties in the rate proceeding of its intention to support the petition, Staff entered into a stipulation with the Company dated May 28, 2009, which recommends that we approve the requested deferral. Staff states that no party has expressed opposition to the terms of the stipulation.

Discussion - We approve the terms of the stipulation and grant the relief requested by Central Hudson in its deferral petition.

V. CONCLUSION

With the modifications described in the foregoing discussion, we adopt the recommendations of the April 10, 2009 Recommended Decision as to the rates, charges and terms of service of Central Hudson Gas & Electric Corporation for electric and gas service for the rate year commencing July 1, 2009.

The Commission orders:

1. Central Hudson Gas & Electric Corporation is directed to file cancellation supplements, effective on not less than one day's notice, on or before June 26, 2009, cancelling the tariff amendments and supplements listed in Appendix I to this order.

2. Central Hudson Gas & Electric Corporation is directed to file, effective on not less than one day's notice on July 1, 2009, such further tariff revisions as are necessary to effectuate the provisions adopted by this order. The Company shall serve copies of its filing on all active parties in these cases. Any comments on the compliance filing must be received at the Commission's offices within 14 days of service of the Company's proposed amendments. The amendments specified in the compliance filing shall not become effective on a permanent basis until approved by the Commission.

3. The requirement of Section 66(12)(b) of the Public Service Law that newspaper publication be completed prior to the effective date of the proposed amendments directed in Clause 2 above is waived and the Company is directed to file with the Commission, not later than six weeks following the amendments' effective date, proof that a notice to the public of the changes made by

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the amendments has been published once a week for four successive weeks in newspapers having general circulation in the areas affected by the amendments.

4. Central Hudson Gas & Electric Corporation shall file modifications to its tariff to implement effective August 1, 2009, voltage-specific electric loss factors determined in accordance with the findings of the Recommended Decision in this case.

5. Within 60 days following the issuance of this order, Central Hudson Gas & Electric Corporation shall submit a plan for implementation of expansion of its Hourly Pricing Program. The plan shall be consistent with the recommendations set forth in the Recommended Decision, and a copy shall be served on all customers who will be added to the program as a result of the expansion.

6. The Retail Access Collaborative for Central Hudson Gas & Electric Corporation shall be continued. Staff shall schedule a meeting of the collaborative within 30 days after issuance of this order to consider the funding of retail access initiatives from the deferred balance attributable to the Competition Education Fund. Staff shall report the recommendations of the collaborative to us no later than six months following the initial meet- ing.

7. Within seven months following the issuance of this order, Central Hudson Gas & Electric Corporation shall perform a voltage-specific study of electric losses on its system, and shall file a report of its findings with the Commission. Copies of the report shall be served on all active parties to this proceeding.

8. Within fifteen days following the issuance of this Order, Central Hudson Gas & Electric Corporation is directed to file with the Secretary, and serve on all existing active parties, the June 15 Report and the supplemental information described in the body of this order to describe the manner in which it will implement the austerity adjustment described in the body of this order. Such filing will identify, *inter alia*, the capital and expense reductions Central Hudson Gas & Electric Corporation will be using to implement this austerity adjustment; the impacts, if any, on service quality or reliability which may result from these reductions; the future costs or increases in revenue requirement in later periods that may result from these reductions; and each capital and expense reduction that was considered, but not included, in the austerity program and the reasons why the proposed reduction was not included. Any party may file and serve comments on the Company's filing within fifteen days after the filing is made.

9. The petition of Central Hudson Gas & Electric Corporation in Case 09-M-0004 is granted, and the Company is authorized to defer incremental restoration costs incurred as a result of the December 11, 2008, ice storm in the amount of $3,341,887.

10. Except as herein granted, all exceptions to the April 10, 2009, Recommended Decision are denied.

11. Except as specified herein, the April 10, 2009, Recommended Decision is adopted as part of this order.

12. The Secretary is authorized, upon a showing of good cause, to extend the filing deadlines set forth in the body of this order.

*41 *Appendix I*

Filings by CENTRAL HUDSON GAS & ELECTRIC CORPORATION

Amendments to Schedule P.S.C. No. 15 - Electricity

Original Leaf No. 163.5.3

First Revised Leaves Nos. 169.2, 205.2

Second Revised Leaves Nos. 53.7, 135.1, 163.5.1

Third Revised Leaves Nos. 133, 163.5.2, 179, 196, 206.2, 218.2, 248, 272.7

Fourth Revised Leaves Nos. 107, 135, 211.1, 222.2, 231

Fifth Revised Leaves Nos. 136, 139, 165.1, 222.1, 262

Sixth Revised Leaves Nos. 134, 137, 169.1, 186.1, 206.1, 207, 218.1, 221, 226

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Seventh Revised Leaves Nos. 109, 138, 184.2.1, 205.1, 206, 219

Eighth Revised Leaves Nos. 105, 165, 178, 185, 211, 217, 222

Ninth Revised Leaves Nos. 104, 169, 186, 205, 218, 220, 246, 247

Tenth Revised Leaf No. 246.1

Eleventh Revised Leaves Nos. 194, 210

Supplement Nos. 38, 39

Amendments to Schedule P.S.C. No. 12 - Gas

Third Revised Leaves Nos. 121, 195

Fourth Revised Leaf No. 212

Fifth Revised Leaves Nos. 153, 171, 172

Sixth Revised Leaves Nos. 72, 151, 152 158

Seventh Revised Leaves Nos. 68, 181, 193

Eighth Revised Leaf No. 126.1

Ninth Revised Leaves Nos. 124.1, 188, 206

Tenth Revised Leaves Nos. 149, 186, 191

Eleventh Revised Leaf No. 126

Supplement Nos. 31, 32

TABLETABULAR OR GRAPHIC MATERIAL SET FORTH AT THIS POINT IS NOT DISPLAYABLE

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FOOTNOTES

FN1 Notice of the Company's filings was published in the *New York State Register* on November 12, 2008 (SAPA Nos. 08-E-0887SA1 and 08-G-0888SA1). No comments other than those discussed herein were received.

FN2 The effective date of the Company's filing was suspended by the Commission through June 27, 2009, by Order Suspending Major Rate Filing issued on August 25, 2008, and a Further Suspension of Rate Filings issued on December 11, 2008.

FN3 Case 03-E-0640, *et al., Proceeding on Motion of the Commission to Investigate Potential Electric Delivery Rate Disincentives Against the Promotion of Energy Efficiency, Renewable Technologies and Distributed Generation,* Order Requiring Proposals For Revenue Decoupling Mechanisms (issued April 20, 2007).

FN4 The record created includes 2,424 pages of transcript and 170 exhibits.

FN5 EEI Policy Statement at 5.

FN6 EEI Policy Statement at 2.

FN7 Case 08-E-0539, *Proceeding on Motion of the Commission as to the Rates, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service,* Order Establishing Rates For Electric Service (Con Edison Order) (issued April 24, 2009), p. 342.

FN8 Rate allowances for head count and variable pay are discussed below.

FN9 Con Edison Order, pp.341-344.

FN10 Case 09-M-0435, *Proceeding on Motion of the Commission Regarding the Development of Utility Austerity Programs,* Notice Requiring the Filing of Utility Austerity Plans (May 15, 2009).

FN11 The Company also notes that to contain costs in recent years it was able to maintain its operations with a headcount of 825. While we

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have allowed a headcount of 840 in our rate determination herein, the Company may wish to consider extending the lower headcount, through attrition and fewer new hires, as an austerity measure until economic conditions improve.

FN12 In this vein, we note that our preliminary review of the Company's June 15 Report indicates that its proposals regarding tree-trimming and stray-voltage inspections do not appear consistent with this standard and, as such, do not appear to be in the public interest.

FN13 Con Edison Order, pp. 90-91.

FN14 Case 90-G-0734, *et al., Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of National Fuel Gas Distribution Corporation for Gas Service*, Opinion 91-16 (issued July 19, 1991), p. 9.

FN15 Con Edison Order, p. 53.

FN16 As noted by Staff in its Brief Opposing Exceptions, the premium pay percentage applied in calculating labor expense for semi-monthly employees should not be applied to the variable pay which we have excluded.

FN17 Case 09-M-0311, *Implementation of Chapter 59 of the Laws of 2009 Establishing a Temporary Annual Assessment Pursuant to PSL 18-a (6)*, Notice Requesting Comments (issued April 28, 2009).

FN18 Case 09-M-0004, *Petition of Central Hudson Gas & Electric Corporation to Defer Ice Storm Recovery Costs.*

FN19 Case 04-M-0159, *et al., Proceeding on Motion of the Commission to Examine the Safety of Electric Transmission and Distribution Systems*, Order Adopting Changes to Electric Safety Standards, (issued December 15, 2008) (Electric Safety Standards Order).

FN20 Con Edison Order, p. 110.

FN21 Con Edison Order p. 106.

FN22 In addition, as Staff correctly points out in its Brief Opposing Exceptions, the update for this expense is to be based on the most recent assessment information available and should not include a projection of future assessments.

FN23 Case 29465, *Proceeding on Motion of the Commission as to the Proposed Accounting and Ratemaking Procedures to Implement Requirements of the Tax Reform Act of 1986 as they Affect Public Utilities* (issued July 7, 1987).

FN24 Con Edison Order p. 120-21.

FN25 Con Edison Order, pp. 134-137.

FN26 Con Edison Order, pp. 128.

FN27 Case 08-G-0609, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Niagara Mohawk Power Corporation for Gas Service*, Order Adopting the Terms of a Joint Proposal and Implementing a State Assessment Surcharge (issued May 15, 2009), p. 6.

FN28 Case 00-M-0504, *Proceeding on Motion of the Commission Regarding Provider of Last Resort Responsibilities, the Role of Utilities in Competitive Energy Markets, and Fostering the Development of Retail Competitive Opportunities*, Statement of Policy on Unbundling and Order Directing Tariff Filings (issued August 25, 2004), p. 36.

FN29 RD, p. 101.

FN30 *See e.g.*, Case 01-G-1821, *Central Hudson Gas & Electric Corporation*, Order Regarding Deferred Accounting Plan for 2002 (issued October 25, 2002).

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*42 EDITOR'S APPENDIX

PUR Citations in Text

[N.Y.] Re Investigation of Potential Electric Delivery Rate Disincentives Against the Promotion of Energy Efficiency, 256 PUR4th 477, Case 03-E-0640, Apr. 20, 2007.

[N.Y.] Re Investigation of Potential Gas Delivery Rate Disincentives Against the Promotion of Energy Efficiency, 256 PUR4th 477, Case 06-G-0746, Apr. 20, 2007.

END OF DOCUMENT

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ATTACHMENT L

Westlaw.

H
Slip Copy

Tariff filing of Green Mountain Power Corporation requesting an 11.95% increase in its rates, effective May 29, 2006
7175

Petition of Green Mountain Power Corporation for approval of an alternative-regulation plan

7176

Vermont Public Service Board
Order entered: December 22, 2006

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Appearances: Donald J. Rendall, Jr., Esq. for Green Mountain Power Corporation; Peter H. Zamore, Esq. Benjamin Marks, Esq. Sheehey Furlong & Behm P.C. for Green Mountain Power Corporation; Leslie A. Cadwell, Esq. James Porter, Esq. for Vermont Department of Public Service; Leonard H. Singer, Esq. James S. King, Esq. Couch White, LLP for International Business Machines Corporation; James A. Dumont, Esq. for AARP; Sandra Levine, Esq. for Conservation Law Foundation; Frank Fontana, Esq. for International Business Machines Corporation

James Volz, David C. Coen and John D. Burke

In this Order, the Vermont Public Service Board ("Board") approves a Memorandum of Understanding ("MOU") between Green Mountain Power Corporation ("GMP" or the "Company") and the Department of Public Service ("Department") in which these parties agreed to a 9.09 percent rate increase for GMP ($20.043 million above the existing rates), effective for service-rendered on or after January 1, 2007. GMP originally requested an increase of 11.95 percent, but in the MOU agreed with the Department that the 9.09 percent rate increase would result in just and reasonable rates, assuming the Board simultaneously approved an alternative regulation plan (the "Plan") for GMP. [FN1]

FN1. The Department and GMP stipulated that the rate increase should be 9.58 percent if the Board did not approve the Plan by December 29, 2006. The MOU, including the Plan, is attached to this Order.

We also approve an alternative regulation plan for GMP that will govern the Company for the next three years. The Plan will, in many ways, strengthen the connection between GMP's costs and its rates. It will permit annual rate adjustments to reflect changes in operating costs. In addition, the Plan provides for regular (quarterly) rate adjustments to flow through to ratepayers increases or decreases in power costs (which make up the majority of GMP's total costs). This has the effect of shifting risk associated with varying power costs to ratepayers; in recognition of this risk shift, the Plan provides a lower return on equity (" **ROE**"). Through this framework, and other provisions, the Plan will enable GMP to continue to have a reasonable opportunity to recover its operating costs and earn a fair return on equity. Like the rate increase, the specific elements of the Plan are based upon the MOU between the Department and GMP.

International Business Machines Corporation ("IBM") opposes both the magnitude of the rate increase and approval of the alternative regulation plan. The Conservation Law Foundation ("CLF") also argues that the Plan is not consistent with the statutory requirements for

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such plans in 30 V.S.A. § 218d.

We have considered these objections and are persuaded that we should approve the MOU. The evidence indicates that the rate increase of 9.09 percent will result in rates that are just and reasonable. No party has presented convincing evidence that would support a lower rate increase.

We also find that, on balance, approval of the alternative regulation plan is in the best interest of both GMP and its ratepayers. The Plan provides clear benefits to GMP. It will improve the Company's financial position by allowing more rapid pass through of cost changes, particularly power costs that can vary significantly due to changes in the wholesale market. This improvement will help GMP obtain capital at more favorable rates than it could otherwise. The enhanced financial posture and lower capital costs will, in turn, help GMP as it begins to negotiate replacements for the two major long-term contracts for power from the Vermont Yankee Nuclear Power Station ("Vermont Yankee") and Hydro-Quebec that expire in 2012 and 2015, respectively.

The Plan also should benefit ratepayers over its term. The direct benefits include a lower return on equity (which reduces rate increases) and the possibility that rates can be further reduced by the earnings-sharing provisions of the Plan if GMP can reduce costs and operate more efficiently, thereby improving its earnings. Moreover, customers are likely to derive indirect benefits as a result of these incentives for GMP to provide least-cost energy service to its customers. Specifically, any cost savings that result from GMP's efforts to improve its earnings will eventually be passed on to ratepayers through the mandatory adjustments in the Plan. The mechanisms that allow GMP to flow-through power costs more quickly may also benefit ratepayers as they reduce GMP's need to enter into hedging arrangements that would normally be charged to ratepayers. Finally, to the extent that GMP's improved financial position helps it obtain favorably-priced, long-term power arrangements, ratepayers will, over time, benefit from any power cost savings that result.

Significantly, the Board, the Department, consumer groups, ratepayers, and other interested persons will continue to have an opportunity to evaluate the reasonableness of the various rate adjustments and the Board can open investigations if these changes may not be warranted. We also expect to carefully review the allocation of risks and benefits over the next three years to provide a sound basis for evaluating changes in the future. It is essential that the Plan result in a fair distribution of those risks and benefits. In particular, we are concerned that the Plan shifts risks from GMP's shareholders to Vermont ratepayers. No party presented evidence that permits us to accurately quantify the magnitude of this reallocation of risks. This is also the first alternative regulation plan for an electric utility in Vermont, so we do not have the benefit of direct experience. Due to this uncertainty, it is not clear that the reduction of GMP's **ROE** by 50 basis points fully compensates ratepayers for the changes in risk. The Department and GMP have persuaded us that GMP's improved financial status will provide long-term financial benefits to ratepayers that are not directly quantifiable and are likely to outweigh any change to the risk allocation. In addition, we expect that the incentives inherent in the Plan will encourage efficient operation of GMP and promote the state's energy goals. Because of these expectations, we find the overall balance of risks and rewards fair. We do intend to continue to evaluate this issue as we monitor the Plan.

II. PROCEDURAL HISTORY

On April 18, 2006, GMP filed a petition and revised tariffs with the Board, accompanied by cost of service schedules, requesting an 11.95% increase in its retail rates, effective on a service-rendered basis commencing May 29, 2006 (Tariff Filing No. 7628). [FN2] GMP asserted that the proposed rate increase will produce approximately $25 million in additional annual revenues. The Company cites rising power and transmission costs as the primary need for the rate increase. At the same time, GMP filed a petition requesting approval of an alternative regulation plan pursuant to 30 V.S.A. § 218d.

FN2. On May 26, 2006, the Company filed corrections to its testimony and exhibits that sup-

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ported a revised revenue requirement of 11.78%.

On May 12, 2006, the Department, pursuant to 30 V.S.A. § 225, informed the Board that it had reviewed the tariff filing and recommended that it be suspended and investigated. The Board issued an Order on May 22, 2006, suspending the rate filing under Section 226, opening an investigation and scheduling a prehearing conference. [FN3]On the same date, the Board also scheduled a prehearing conference to consider the proposed alternative regulation plan.

FN3. Order Suspending Tariff Filing and Notice of Prehearing Conference, dated May 22, 2006.

The Board convened a prehearing conference on June 2, 2006. Subsequently, the Board granted intervention on a permissive basis to IBM, AARP and CLF. The Board adopted a schedule for this proceeding at that time. [FN4]The Board also approved a Protective Agreement between the Company and the Department on June 8, 2006.

FN4. Prehearing Conference Memorandum of June 16, 2006.

The Board convened an informal workshop on June 27, 2006. At that time, the Company explained its proposed Plan. After the discussions in the workshop and later discussions with parties, GMP filed revisions to the proposed Plan on July 21, 2006.

The Board also held a public hearing using Vermont Interactive Television on July 12, 2006. Two members of the public expressed comments.

The Company and the Department entered into a Memorandum of Understanding ("MOU") dated August 22, 2006, providing for a revised rate increase, a revised alternative regulation plan, and other Company obligations relating to the Plan. On the same date, the Company filed the Plan, the MOU, and supplemental testimony and the Department filed testimony in support of the MOU. The Company filed rebuttal testimony on September 1, 2006, and CLF, AARP and IBM filed surrebuttal testimony on September 15, 2006.

On September 19, 2006, GMP filed a motion to accord confidential treatment to certain information during the evidentiary hearings, which the Board granted during the first day of hearings.

The Board held evidentiary hearings in Montpelier on September 26 and 27, 2006, to consider both the proposed rate increase and the alternative regulation plan. The Board also heard testimony regarding proposed revisions to the Company's Service Quality & Reliability Plan ("SQRP"); GMP filed the revised SQRP on September 28, 2006, requesting that the Board approve it. [FN5]

FN5. Letter from Peter H. Zamore to Susan M. Hudson, dated September 28, 2006.

On September 29, 2006, GMP filed a Settlement Agreement between the Company and AARP, which included a pilot program that will alter GMP's disconnection policies for low-income customers. AARP agreed to withdraw its testimony and not oppose the MOU between the Department and GMP. In its letter, the Company requested Board approval of the AARP Settlement Agreement. On October 18, 2006, the Board approved the AARP Settlement Agreement.

III. POSITIONS OF THE PARTIES

GMP

GMP argues that the Board should approve the MOU, with an attendant rate increase of 9.09% if the Plan is approved and 9.58% if the Plan is not approved. Also consistent with the MOU, the Company and the DPS support an allowed **ROE** of 10.25% if the Plan is approved and 10.75% if the Plan is not approved. GMP contends that rate increase it proposes is justified as demonstrated by its cost of service filing, as amended and adjusted following negotiations with the Department.

GMP also requests that the Board approve the Plan. GMP maintains that the Plan presents opportunities to

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improve traditional ratemaking and lower costs to consumers. GMP asserts that traditional ratemaking produces numerous costs for consumers, including rate case expenses, lag between cost changes and rate changes, and increased uncertainty that may raise the utility's cost of capital. GMP submits that the Plan eliminates most of these costs and the uncertainty, which will benefit ratepayers. In addition, GMP argues that the Plan will reduce customer costs in other ways, including lower cost of capital, incentives to the Company to reduce costs, a cap on earnings, and GMP's absorption of certain cost changes. Finally, GMP contends that the Plan will improve GMP's financial stability and improve the Company's access to capital.

Department

The Department recommends that the Board approve the MOU "because it provides for just and reasonable rates under traditional regulation and establishes a non-traditional rate regulation plan that complies with § 218d." [FN6]The Department also contends that the revenue requirement is based upon a reasonable **ROE**, which is within the range of the record evidence. The Department argues that the Plan is important to allow GMP to maintain access to low cost capital over the next several years, while simultaneously keeping rates at reasonable levels.

FN6. Department Brief at 1.

IBM

IBM contends that the rate increase set out in the MOU is excessive. IBM asserts that we should reduce the amount of the increase to reflect a lower **ROE** (9.5% if the Plan is approved and 10% otherwise). It also argues that power costs should be reduced to reflect the elimination of (1) 50% of the incremental replacement power costs GMP has incurred as a result of Hydro-Québec's option under the 9701 contract, (2) any costs associated with rate year balancing transactions with ISO-New England ("ISO-NE"), (3) the proposed annual accrual of $315,000 to fund Vermont Yankee unscheduled outage replacement power costs, and (4) certain costs associated with GMP's replacement power contract with Morgan Stanley.

IBM further maintains that the Plan is not in the public interest and should be rejected or significantly modified. According to IBM, the Plan will increase rate volatility, reduce utility incentives to manage costs, unfairly allocates risk, and may lead to rates that are not just and reasonable. IBM also avers that the Plan does not provide accurate price signals to customers, largely because the adjustment to rates based upon changing power costs actually is allowing recovery for past costs rather than charging customers rates that reflect prevailing market conditions. If the Board elects to approve the Plan, IBM asserts that the Board should modify the Earnings Sharing Adjustor calculation so that GMP may not recover certain energy-related power costs that are specifically excluded from the Power Adjustor.

AARP

AARP reached a settlement with GMP that these parties filed on September 29, 2006. The Board approved the settlement by Order dated October 18, 2006. AARP took no position on the remaining issues.

CLF

CLF states that it strongly supports the use of alternative regulation within Vermont because it offers the opportunity "to better align good decision making with the ability to earn a profit." [FN7]Nonetheless, CLF argues that the proposed Plan does not promote the public good, offer incentives for innovation, improved performance, and least-cost provision of energy services, nor provide rates that are just and reasonable. As a result, CLF asserts that the Plan does not establish a "reasonably balanced system of risks and rewards that encourages the company to operate as efficiently as possible" as required by Section 218d(a)(7). CLF recommends that the Board not approve GMP's plan, but instead allow GMP to submit a revised plan within 60 days that addresses the deficiencies CLF identifies.

FN7. CLF Brief at 2.

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IV. GMP'S RATE REQUEST

A. Findings

1. Under the MOU, the Company and the Department agreed that a 9.09% rate increase effective for service-rendered January 1, 2007, is appropriate if the Plan is approved, and that a 9.58% increase is appropriate if the Plan is not approved. The MOU further provides that if the Plan is approved after January 1, 2007, the 9.58% increase would become effective on January 1, 2007, to be reduced to 9.09% effective on a bills-rendered basis on the first billing cycle of the month following the date on which the Plan becomes effective pursuant to 30 V.S.A. § 218d(g); exh. GMP-AJK-3 at 5.

2. The cost-of-service analysis is based on a 2005 test year. The adjusted test year (rate year) is 2007. Exh. GMP-AJK-6 at 1-2; exh. GMP-AJK-7 at 1-2, Kvedar pf. at 6.

3. The 9.09% rate increase reflects a revenue requirement of $228,265,000, based on operating expenses of $237,413,000, a 10.25% **ROE**, and a $227,513,000 rate base. Based on test year revenues of $209,241,000, the resulting revenue deficiency is $19,024,000. Exh. GMP-AJK-6 at 1-4.

4. The 9.58% rate increase reflects a revenue requirement of $229,284,000, based on operating expenses of $237,832,000, a 10.75% **ROE**, and a $227,513,000 rate base. Based on the same year revenues, the resulting revenue deficiency is $20,043,000. [FN8]Exh. GMP-AJK-7 at 1-4.

FN8. The difference between the operating expenses under the 9.09 percent and 9.58 percent rate increases is attributed to the tax effect of the differing **ROEs**.

5. The difference in the revenue deficiency between the 9.58% rate increase and the 11.95% increase reflected in the Company's April 14 Petition is as follows:

April 14 revenue deficiency	$24,639,000
Department power cost adjustments	(2,928,000)
Department fuel savings adjustment	(101,000)
Vermont Yankee reserve	315,000
Adjusted return on equity	(1,121,900)
50% of remaining Department adjustments	(760,500)
Total adjustment	(4,596,400)
MOU revenue deficiency	$20,042,600

The revenue deficiency associated with the 9.09% rate increase is identical, except that the deficiency is reduced by $2,141,000 when based on a 10.25% **ROE**. Kvedar supp. pf. at 3.

6. The 9.58% revenue increase in the absence of a Plan and 9.09% revenue increase under a Plan would result in just and reasonable rates. Behrns pf. at 12; Kvedar supp. pf. at 2; exh. GMP-AJK-3 at 5; findings 1-18.

1. Return on Equity

7. GMP recommended a return on equity in the range of 10.7-11.5% (if the Plan is not adopted). This is based on the discounted cash flow ("DCF"), Capital Asset Pricing Model ("CAPM") and alternative risk premium ("Risk Premium") approaches incorporating information through August 11, 2006, as well as the incorporation of a .55% small size premium. Hevert reb. pf. at 47; Hevert supp. pf. at 2-3.

8. Without a small size premium, GMP's range of **ROE's** is between 10.15%- 10.95%. Hevert reb. pf. at

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46.

9. IBM presented testimony indicating that the appropriate **ROE** is within the range of 9.5-10.4%. Gorman pf. at 20.

10. The effect of adopting the Plan would be a reduction in the **ROE** of between 36 basis points to 152 basis points, with a mean of roughly 90 basis points. Hevert supp. pf. at 4.

11. The 50 basis point reduction supported by the MOU if the Plan is adopted is within this range. Hevert supp. pf. at 5.

12. The proposed 10.75% **ROE** (if the Plan is not approved) is within the range of 10.15% to 10.95% range supported by the Company, based on DCF, CAPM and risk premium approaches. Hevert supp. pf. at 2-3; Hevert reb. pf. at 46.

13. Similarly, a fifty basis point **ROE** reduction if the Plan is adopted is within the range of appropriate adjustments to **ROE**. Hevert supp. pf. at 4-5.

2. The 9701 Contract

14. Under the 9701 contract, the Company granted Hydro-Québec the option to recall specified annual amounts of the power sold under the Vermont Joint Owners Agreement at a specified price, in exchange for a one-time payment of $8 million. Gorman pf. at 29.

15. The cost to cover Hydro-Québec's exercise of the option is required to meet the Company's obligation to supply power under the 9701 contract. Tr. 9/26/06 at 146 (Brown).

3. Balancing Transactions

16. GMP purchases additional energy from the ISO-NE power pool during periods of higher than anticipated demand. Brown pf. at 5.

17. During periods of lower demand, GMP resells this energy to the power pool. *Id.*

18. For 2007, GMP projects that its ISO-NE purchases will result in a net loss of approximately $2.04 million. Brown reb. pf. at 2-3; tr. 9/26/06 at 148-49 (Brown).

4. Insurance for Unplanned Outage at Vermont Yankee

19. GMP purchases insurance against the possibility of increased costs to the Company arising from unplanned outages at Vermont Yankee. The cost of this insurance is $810,000. Gorman pf. at 35.

20. The Company proposes to include an annual $315,000 in its cost-of-service as a reserve to be used to pay costs associated with an unscheduled Vermont Yankee outage not covered by the Company's outage insurance. Griffin supp. pf. at 1.

21. Assuming it is not used due to outages at Vermont Yankee, the reserve will grow over time, which would permit the outage insurance deductible to be increased each year, thereby benefitting customers by reducing the cost of insurance premiums. Griffin supp. pf. at 2-3; tr. 9/26/06 at 122 (Griffin).

22. The reserve would also benefit customers because it would be deducted from rate base. Griffin supp. pf. at 1.

23. The Vermont Yankee outage reserve is a reasonable appropriate supplement to outage insurance that benefits customers. Griffin supp. pf. at 1-3; findings 19-22.

B. Discussion

IBM maintains that the cost-of-service supported by the MOU should be reduced to reflect five adjustments: (1) an **ROE** no higher than 9.5 percent under an alternative regulation Plan; (2) disallowance of half of the replacement power costs associated with the Hydro-Quebec 9701 contract; (3) reduction of Morgan Stanley replacement power costs; (4) elimination of any "balancing transaction" amounts; and (5) elimination of the Vermont Yankee Nuclear Power Station ("Vermont Yankee") outage reserve.

We have examined the MOU and the objections that IBM has raised to certain elements of the MOU. We

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find that overall, the MOU will produce just and reasonable rates and thus is in the public interest. The MOU, while still requiring a large increase in rates, reflects a reduction in the revenue deficiency that the Company sought to recover from ratepayers.

1. Return on Equity

Neither the law nor regulatory precepts prescribe a specific methodology for setting the appropriate return on equity. Instead, the Board has substantial discretion to weigh factors so as to achieve the overarching goal of authorizing a return on equity that is fair and reasonable to all stakeholders. The critical element is the reasonableness of the result, not necessarily the methodology used to achieve it. [FN9]The basic standard is well-established:

> FN9. In re *FPC v. Hope Natural Case Co.*, 320 U.S. 591, 602 (1944).

A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. [FN10]

> FN10. *Bluefield Water Works & Improvement Co. v. Public Serv. Comm'n*, 262 U.S. 679, 692-93 (1923).*See also Duquesne Light Company v. Barasch*, 488 U.S. 299, 310 (1989).

These principles are reflected in the statutes governing the Board's decisions, and have been endorsed repeatedly by the Vermont Supreme Court.

In this proceeding, GMP and the Department have agreed to an **ROE** of 10.75%, which would be reduced by 50 basis points (to 10.25%) if the Board approves the Plan. This reduction in the **ROE** reflects the fact that the Plan transfers substantial risk from the Company to its ratepayers. GMP also presented evidence that the appropriate range of **ROE** should be from 10.70 to 11.50 percent if a small company premium is included or from 10.15 to 10.95 percent without the premium. By comparison, IBM recommends an **ROE** of 9.9 percent. Its testimony shows a range of 9.5 to 10.4 percent for the **ROE**.

The analyses presented by both parties use three models. These are the discounted cash flow ("DCF"), risk premium, and the capital asset pricing model ("CAPM") approaches. The parties differ, however, on certain of the inputs to these models. For example, IBM disputes the selection of some of the companies GMP uses as a proxy group (in particular Northeast Utilities ("NU"), arguing that it is undergoing a strategic transformation); [FN11] the inputs to the Company's risk premium analysis (dividend history and growth rates, expected market returns, stock price performance, use of companies' beta to measure risk, and the effect of interest rates); and the proposed "small company premium" of 55 basis points. For its part, GMP contests the dividend growth rate that IBM uses in its analysis.

> FN11. Gorman pf. at 24.

We find that a reasonable range for setting the **ROE** would be between 10.00 and 10.95 percent. In reaching this conclusion, we have considered the various analyses presented by GMP and IBM and the criticisms each has leveled at the other's studies. The two most significant disagreements arise on the appropriateness of including NU in the proxy groups and the addition of a small company premium. On the first issue, IBM has not shown that the inclusion of NU is unreasonable. While NU may be undergoing a transformation, the evidence shows that Value Line recently stated that it expected NU to focus on regulated operations and that unregulated operations should be minimal. [FN12]Thus, we see no reason to exclude it.

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FN12. Hevert reb. pf. at 12-13.

However, we also find that GMP has not demonstrated the reasonableness of including a premium to account for the small size of GMP relative to other companies. GMP has not shown that it has greater risk than other companies in its proxy group. [FN13]In fact, GMP's risk profile, earnings growth, and current favorable access to capital all appear contrary to the Company's justification for a 55 basis points premium.

FN13. Gorman pf. at 23-24.

The MOU's proposed **ROE** of 10.75 percent thus lies within the range that we find to be reasonable, albeit at the high end of that range. In the context of the settlement agreement, we will accept this higher **ROE**. In so doing, we rely heavily on the Department's agreement to the **ROE**. We note that when the changes in the interest rates are considered, the proposed 10.75 rate is also consistent with the **ROE** that we granted GMP in the last investigation of the Company's rates - Docket 6867.

The remaining question is the appropriate adjustment to the **ROE** to reflect approval of an alternative regulation plan. There is no question that GMP will shed substantial risk, which will now be passed on to ratepayers. For example, under the Plan (as we describe below), GMP will pass through power costs and will regularly adjust base rates to reflect changes in operating costs. GMP presented evidence that an appropriate shift in risk ranged from 36 to 152 **ROE** basis points. [FN14]The Company originally recommended an adjustment of 90 basis points, which was approximately the mid-point of this range. GMP and the Department now recommend a smaller, 50-basis-point adjustment. IBM, by comparison, asks that we continue to include the larger adjustment originally proposed by GMP. [FN15]

FN14. Hevert supp. pf. at 4.

FN15. IBM Brief at 25.

In this Order, we accept the 50-basis point adjustment. We reach this conclusion largely in reliance upon the Department's and GMP's agreement reflected in the MOU and the fact that IBM did not present convincing evidence that it was incorrect. As we discuss below, however, in our consideration of whether the Plan fairly allocates risks and rewards, we are concerned that the selection an **ROE** adjustment at the lower end of the range, coupled with the other elements of the Plan, may provide GMP greater benefits than those received by customers. At this time, we find the allocation to be reasonable, but we will examine this issue closely if GMP asks to renew the Plan later.

2. The 9701 Contract

In 1996, GMP entered into a contract with Hydro-Quebec under which GMP received $8 million. [FN16]In exchange, Hydro-Quebec received the right to recall certain amounts of power sold under the contract with the Vermont Joint Owners. As a result of these call-backs, GMP has incurred additional power costs necessary to purchase replacement power to serve the load that would otherwise be served by the recalled power. GMP's cost-of-service includes these additional replacement power costs.

FN16. Docket 5983 Order of 2/28/97 at 263-265.

IBM proposes that GMP's cost of service should be reduced to reflect a disallowance of one-half of these costs in the adjusted test year ($2.418 million). IBM asserts that the 9701 contract was not entered into to procure power and erodes the value of Hydro-Québec capacity and therefore it is unreasonable to ask customers to pay the full economic losses. [FN17]

FN17. Gorman pf. at 30; tr. 9/27/06 (Gorman) at 8.

The appropriate regulatory treatment of the 9701 contract has been raised before the Board twice previously. First, in Docket 5983, the Board examined the question of whether to amortize the $8 million that GMP received over the remaining life of the Hydro-Quebec Contract. At that time, no party, including IBM, raised concerns about whether the 9701 Contract was prudent, so we did not address the issue. [FN18]However, we

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found that the contract was expected to yield savings of $2.3 million net present value over the life of the contract. [FN19]We also expressed concern that the arrangement was driven largely by short-term financial considerations, and therefore stated that similar arrangements in the future were unlikely to be viewed with favor. [FN20]

FN18. Docket 5983 Order at 216; tr. 9/27/06 at 10-11 (Gorman).

FN19. *Tariff Filing of Green Mountain Power Corp.*, Docket No. 5983, Order of 2/27/98 at 211-213, 263-265 ("Docket 5983 Order"); tr. 9/27/06 (Gorman) at 9.

FN20. Docket 5983 Order at 212, 264; tr. 9/27/06 (Gorman) at 10.

In Docket 6107, IBM proposed to disallow 9701 costs based on a claim of imprudence, but the Board chose not to make a prudence determination or otherwise disallow 9701-related costs because they would not have any impact on the rates set by the Public Service Board. [FN21]We also observed that:

FN21. *Tariff Filing of Green Mountain Power Corp.*, Docket No. 6107, Order of 1/23/01 at 104-105, note 329 ("Docket 6107 Order"); tr. 9/27/06 at 13-14 (Gorman).

Although we do not rule on this proposed cost of service adjustment, we wish to note our skepticism about IBM's contention that it was imprudent for GMP to enter the 9701 agreement. The record does not demonstrate that any other New England utility or indeed other commentator foresaw the extent and degree of volatility that has developed in New England wholesale power markets. Absent that volatility, the 9701 agreement would not have had its adverse effects. [FN22]

FN22. Docket 6107 Order at 105, note 329; tr. 9/27/06 at 15 (Gorman).

No party, including IBM has presented any analysis or review that would call into question GMP's prudence in entering into the 9701 arrangement. Similarly, IBM has not presented any evidence to demonstrate that we should disallow the replacement power costs arising from the 9701 agreement because they were not used-and-useful. [FN23]Absent such information, we see no reason to alter the decision we reached in Docket 6107, or to substantively evaluate the questions of the prudence and used-and-usefulness of these costs. Accordingly, we do not require an adjustment to the Company's cost-of-service due to replacement power costs incurred because of the 9701 contract.

FN23. *See generally*, Gorman pf. at 28-21.

3. Balancing Transactions

GMP engages in both purchases and sales from the regional wholesale power market. In its cost-of-service, GMP included a cost of $2.04 million to reflect the net purchases. [FN24]IBM claims that there should be no allowance for balancing transactions in the cost of service, because the net cost of balancing transactions in 2005 was minimal. [FN25]

FN24. Brown reb. pf. at 3.

FN25. IBM Brief at 19-20.

We do not accept IBM's proposed cost-of-service adjustment. We find that the Company appropriately recalculated Mr. Gorman's conclusion based on a corrected average 2005 sales price, which equates to an allowance of roughly $2 million for the 2007 rate year. Although the Company initially proposed an allowance of roughly $4 million, this amount was adjusted downward by $2 million in the MOU to equal the amount recalculated by Mr. Brown. As a result, IBM's proposed adjustment is rejected.

4. Morgan Stanley Contract Replacement

IBM argues for a reduction of $436,714 to reflect changes to the Company's replacement power cost contract with Morgan Stanley. [FN26]The Company asserts that, under the MOU, GMP agreed to reduce the power cost component of its cost-of-service. These reductions

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to power costs, says GMP, are greater than the adjustment proposed by IBM.

FN26. IBM Brief at 27-28.

We agree that the total reduction to power costs under the MOU are greater than the amount of IBM's proposed disallowance. [FN27]Specifically, the MOU parties agreed to reduce power costs by $2.9 million. But, by its terms, the MOU would not take effect unless approved in whole. Thus, if we were to adopt IBM's adjustment, the evidence now in the record would not support the power cost reduction in the MOU. Moreover, IBM has not shown that the Morgan Stanley contract adjustment is not already incorporated into the DPS adjustment. Accordingly, we find that ratepayers derive greater benefits from the $2.9 million power cost adjustment in the MOU and we reject IBM's proposed reduction.

FN27. Kvedar supp. pf. at 3; Gorman pf. at 28; GMP Reply Brief at 14.

5. Vermont Yankee Outage Insurance

GMP pays $810,000 annually for insurance against the additional replacement power costs that would arise due to an outage at Vermont Yankee. [FN28]The Company proposes to include an annual $315,000 allowance in its cost-of-service as a reserve to be used to pay costs associated with an unscheduled Vermont Yankee outage not covered by the Company's outage insurance. [FN29]This reserve would be deducted from rate base. Thus, GMP asserts that it would provide an additional benefit to ratepayers. The Company also maintains that the reserve would permit the outage insurance deductible to be increased each year, thereby benefiting customers by reducing the cost of insurance premiums. IBM argues that the allowance for the Vermont Yankee outage insurance reserve should be rejected because it is redundant and because the Company provided no supporting analysis. [FN30]

FN28. Gorman pf. at 35.

FN29. Griffin reb. pf. at 1-2

FN30. Gorman pf. at 35.

We do not accept IBM's arguments. Approximately one-third of GMP's power is provided by Vermont Yankee under a favorably-priced contract. An outage at Vermont Yankee can lead to potentially expensive replacement power costs. Historically, for unplanned outages that may entail substantial replacement power costs, GMP has requested and received accounting orders that allow the Company to book and defer these costs for later recovery; in subsequent rate cases, the Board has allowed GMP to recover the deferred costs. Under the Plan, these replacement power costs would be passed on to ratepayers directly through the Power Adjustor.

The reserve is a reasonable approach to addressing the financial exposure to GMP and its customers arising from unplanned outages at Vermont Yankee. [FN31]While we agree with IBM and that outage insurance provides some protection, GMP has shown that the addition of a reserve fund can, over time, provide a more cost-effective approach to providing that protection. This is achieved by the fact that, as the fund grows, it will allow GMP to increase the deductible on its insurance policy, thereby reducing costs. At the same time, in recognition of the fact that the ratepayers have provided the funds, the reserve fund will be deducted from ratebase. We find this approach reasonable.

FN31. In fact, the reserve appears to be reasonable even in the absence of a Plan.

V. THE ALTERNATIVE REGULATION PLAN

A. Findings

1. The Proposed Plan

24. GMP and the Department (through the MOU) have proposed an alternative regulation plan that would take effect February 1, 2007, and terminate on December 31, 2009, except that certain adjustments to GMP's rates would occur at specified dates subsequent to the termination of the Plan. Exh. GMP-AJK-4 at 1.

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25. Under the proposed Plan, GMP would be unable to seek adjustments in rates (except those specified in the Plan) that would be effective before January 1, 2010. *Id.*

26. The proposed Plan establishes a framework for regular rate adjustments for the 2007-2010 period, based on prescribed methodologies. These adjustments would be: (1) annual base rate filings; (2) quarterly power adjustments; and (3) annual earnings reconciliation adjustments. Kvedar pf. at 5-6; exh. GMP-AJK-4 at 1-7; Behrns pf. at 11.

27. The regular rate adjustments under the proposed Plan could mean that customer rates are adjusted four times per year. By contrast, under traditional ratemaking, customer rates change much less frequently. Gorman pf. at 41.

28. The annual base rate adjustment would be subject to suspension, with an April 30 deadline for Board decision. The other adjustments would not be subject to suspension, although the Board could initiate a rate investigation under 30 V.S.A. § 227(b) at any time, on its own motion or upon request, and the retroactive effect of the Board's order would be consistent with that section. Exh. GMP-AJK-4 at 2-4, 7, 9; Allen pf. at 2.

29. Under the proposed Plan, on November 1, 2008, and 2009, GMP would file a cost of service supporting a base rate change to be effective on January 1. The annual filing would be identical to a traditional rate filing, except for the following differences. First, loads and revenues would be based on a forecast for the year the rates would be in effect. Second, increases in non-power costs would be capped at $1.25 million (2008) and $1.5 million (2009). Third, the authorized **ROE** would be adjusted to reflect 50% of the difference between the average ten-year Treasury note yield to maturity (a) as of the last twenty trading days prior to October 15 before the filing, and (b) the later of the last twenty trading days prior to October 15 of the previous year or the last twenty trading days prior to the last day of evidentiary hearings (September 27, 2006). Kvedar pf. at 5-6; exh. GMP-AJK-4 at 1-3; Behrns pf. at 13.

30. The cap on the proposed base-rate adjustor will help ensure that the change in base rates does not rise above approximately 2 percent annually. Allen pf. at 4.

31. The cap on the proposed base rate adjustment could be exceeded to reflect Exogenous Changes, which are defined as cost or revenue changes in excess of $600,000 that relate to certain specified events that are outside the Company's control. These events include changes to statutes, regulations, or accounting rules, loss of load, or certain major unplanned events. Griffin pf. at 5.

32. Pursuant to the MOU, the Department would retain an independent consultant to review the annual base rate adjustment and file a report with the Department and Board at the time the adjustment is filed. Exh. GMP-AJK-3 at 3; Kvedar supp. pf. at 6.

33. Under the proposed Plan, GMP would adjust its rates quarterly based upon the difference between actual power costs and projected costs included in GMP's rates through the Power Adjustor. The Power Adjustor amount would reflect the difference between actual power costs and power costs included in rates during the Measurement Quarter. Smith pf. at 6; exh. GMP-AJK-4 at 5-7.

34. The proposed Power Adjustor would be filed within 45 days after the end of each calendar quarter ("Measurement Quarter") and would be effective for the calendar quarter beginning after the filing (*i.e.*, beginning three months after the Measurement Quarter ends) ("Collection Quarter"). Exh. GMP-AJK-4 at 5.

35. Under the proposed Power Adjustor, power costs related to capacity, transmission and ancillary service charges, which are largely outside the control of the Company, would be passed through completely. Allen pf. at 3.

36. For most of GMP's power costs (including energy charges, market purchase, and fuel costs), the Power Adjustor would only reflect changes in costs (less revenue changes associated with changes in sales volumes) that are greater than the "Power Efficiency Band" of $300,000, and only 90% of the remaining difference

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would be reflected in the quarterly rate adjustment. *Id.* at 5-6; Smith pf. at 6-15.

37. The proposed Power Adjustor specifies that the variance between actual and collected power costs (subject to these limitations) would be divided by projected sales in the Collection Quarter, yielding a positive or negative Power Adjustor rate component for that quarter. The quarterly adjustor would be subject to a quarterly cap of $10/MWh and any difference between the Power Adjustor amount and revenues resulting from the cap would be deferred and recognized in the next quarter. Smith pf. at 6-15; Kvedar supp. pf. at 2; exh. GMP-AJK-4 at 5-6.

38. The proposed Power Adjustor would overcollect or undercollect the target amount if the Company's actual sales volumes differ from the projected volumes. Under the proposed Plan, GMP would track these differences and refund or recover them once per year in the annual rate adjustment or Earnings Sharing Adjustor. Smith pf. at 15-16.

39. The proposed Earnings Sharing Adjustor would be filed by February 15, 2008, 2009, and 2010, and would be effective the following April 1. The adjustor would reflect the difference between the achieved **ROE** for the preceding calendar year, calculated on a regulatory basis, and the **ROE** approved in this case (including the adjustment, if any, associated with Treasury note yields in Finding 29, above). Kvedar pf. at 6; Griffin pf. at 5-6; exh. GMP-AJK-4 at 3-4.

40. Under the proposed Earnings Sharing Adjustor, rates would be adjusted to reflect the difference between actual and target earnings. However, variations within a range of 75 basis points above and below the authorized return would not be subject to reconciliation. In addition, under the proposal, there would be a 50/50 sharing of earnings shortfalls between 75 and 125 basis points below the target return ("Earnings Sharing Band"). *Id.*

41. Under the Earnings Sharing Adjustor, the revenue impact of the variance between target and actual earnings (subject to the Earnings Sharing Band) would be divided by projected sales for the ensuing 12-month collection period, yielding a refund or surcharge to be paid to or assessed from customers over that period. *Id.*

42. Under the proposed Plan, the base rate and earnings sharing adjustments would be reflected as a uniform percentage change to customers' bills and the Power Adjustor would be reflected as a kWh charge. The adjustments would apply to all rate classes except those not typically subject to general rate increases (*e.g.*, special contracts), and the Power Adjustor would apply only to those rate elements that are subject to a charge that varies on a kWh basis. All three adjustments would be implemented on a bills-rendered basis. Exh. GMP-AJK-4 at 1-7.

43. The proposed Plan specifies that the Company would contribute 10% of the Earnings Sharing Band in excess of the Board-approved rate of return on equity to its Power Partners Program. GMP would also match customer contributions to the Company's WARMTH Support Program; the amount contributed by the Company would not be included in rates. *Id.* at 7.

44. GMP also proposes to continue its efforts to promote Vermont-based renewable energy, including its Voluntary Renewable Support Rider, and the 2004 and 2005 Renewables Support Plans. *Id.* at 8.

45. Under the proposed Plan, GMP would continue efforts to expand customer service choices, including load management tariffs and evaluating potential control of small loads. In addition, GMP would file within six months of Plan approval a so-called "virtual choice" proposal for large customers which would provide those customers an option to participate in the procurement of power supply to meet individual customer loads. *Id*; Brown pf. at 5.

46. On each of June 30 of 2008 and 2009, GMP proposes to file a report evaluating the effectiveness of the Plan. Exh. GMP-AJK-2 at 8.

47. The proposed Plan incorporates the Company's SQRP. [FN32] The proposed SQRP is largely consistent with the SQRP that the Board previously approved. The

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most significant changes contained in the September 28, 2006, revisions to the SQRP relate to increased service guarantee payments and a more restrictive performance standard concerning meter reading. [FN33]Kvedar pf.at 8; tr. 9/26/06 (Allen) at 133-34.

FN32. In the MOU, GMP agreed to work with the Department collaboratively on proposed changes to the SQRP. Exh. GMP-AJK-3 at 3-4. The September 28, 2006, filing of the revised SQRP reflects the results of that collaboration.

FN33. By letter dated September 28, 2006, the Company and the Department requested Board approval of the revised SQRP. Letter from Peter H. Zamore to Susan M. Hudson, dated September 28, 2006. No party has filed any objection to the proposed revisions.

2. Other MOU Conditions

48. Under the MOU, GMP would be required to submit examples of the six annual Plan filings (including details concerning power supply and capital expenditures) to the Department by November 1, 2006, consult in good faith with the Department concerning changes, and submit the filings to the Board for approval within 30 days after the Plan is approved. Exh. GMP-AJK-3 at 3; Kvedar supp. pf. at 6.

49. Pursuant to the MOU, GMP would, within 30 days of Board approval of the Plan, submit to the Department a sample of each type of filing to be made under the Plan and consider the Department's recommendations. Kvedar supp. pf. at 6.

50. In the MOU, the Company has agreed to collaborate in good faith with the Department concerning (1) customer information related to the Plan, (2) a fixed price offering to begin by November 1, 2007, (3) any changes to the SQRP (which were filed by letter dated September 28, 2006, before the October 1, 2006 deadline in the MOU) and (4) the Plan evaluations. Exh. GMP-AJK-3 at 3-4.

51. In the MOU, GMP and the Department agree that "this MOU and any order approving this MOU relates [sic] only to the MOU Parties and shall not be construed as having precedential or any other impact on proceedings involving other utilities."Exh. GMP-AJK-3 at 6.

52. In the MOU, GMP and the Department further agree that:

the MOU and any order approving the MOU shall not be construed by any party or tribunal as having precedential impact on any future proceedings involving the MOU Parties, except as necessary to ensure performance of this MOU or to enforce an order of the Board resulting from this MOU.
Exh. GMP-AJK-3 at 6.

3. Statutory Findings

a. Incentives for Innovations and Improved Performance (§ 218d(a)(1))

53. The Plan establishes a system of regulation in which the Company has clear incentives to provide least-cost energy service to its customers. The Plan provides for regular and timely adjustments to reflect costs that the Company would incur to hedge against costs it cannot control, (2) the Earnings Sharing and Power Efficiency Bands create incentives to reduce costs by permitting the Company to retain the associated benefits and (3) the Plan does not displace the Company's Integrated Resource Planning obligations. Brown pf. at 3; Allen pf. at 6-8; findings 24-47, above.

b. Just and Reasonable Rates (§ 218d(a)(2))

54. The Plan provides just and reasonable rates for service to all classes of customers because adjustments will be implemented for all rate classes that are subject to general rate changes, because the Power Adjustor will be implemented on a basis that reflects most of its costs (energy), and because the remaining adjustments will be implemented on a uniform percentage basis, consistent with traditional rate changes. Kvedar pf. at 10; Allen pf. at 6; findings 24-47, above.

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c. Safe and Reliable Service (§ 218d(a)(3))

55. The Plan results in the delivery of safe and reliable service through incorporation of the Company's SQRP. Morris pf. at 5; Allen pf. at 6.

d. Incentives to Provide Least-cost Energy Service (§ 218d(a)(1))

56. The Plan provides incentives for innovations and improved performance that advance state energy policy such as increasing reliance on Vermont-based renewable energy and decreasing the linkage between sales and earnings. The Plan allows the Company to pursue innovations and policy initiatives without undue financial risk or the need for a traditional rate filing. Brown pf. at 3; Allen pf. at 8; findings 24-47, above.

e. Improved Quality of Service, Reliability, and Service Choices (§ 218d(a)(5))

57. The Plan promotes improved quality of service and reliability service through incorporation of the Company's SQRP and the improvements proposed by the Company and the Department. Morris pf. at 5; tr. 9/26/06 at 105-107 (Morris), 132-143 (S. Allen); finding 47.

58. The Plan promotes improved service choices through (1) the "virtual choice" proposal (if implemented), (2) the obligation to collaborate in good faith with the Department to provide an annual, fixed price service offering, (3) the low-income pilot program, and (4) by encouraging further innovation through the reduction in financial risk. Exh. GMP-AJK-3 at 4; exh. GMP-AJK-4 at 8; exh. GMP-5; Brown pf. at 4; Allen pf. at 6; Finding 45, above.

59. The proposed Plan promotes service choices by providing GMP with financial incentives to develop service choices that reduce costs. This effect is achieved through the Power Efficiency Band and Earnings Sharing Band. In addition, the reduction of financial risk may provide incentives to expand service choices. Brown pf. at 4; Allen pf. at 6.

60. Pursuant to the AARP settlement, the Company will initiate a one-year pilot program, beginning November 1, 2006, in which low-income customers will be treated the same as customers 62 or older for purposes of disconnections under Board Rule 3.304(D)(2). In addition, the Company will determine low-income status based on information from various low-income programs and agencies, will work to improve the available data, will modify its reports under Rule 3.308(B) to identify the number of actual and avoided disconnects under the pilot program, and will provide copies of the reports to AARP. Exh. GMP-5.

f. Encourage Innovation in the Provision of Service (§ 218d(a)(6))

61. The Plan encourages innovative provision of service by creating incentives to reduce costs, such as through innovative and efficient approaches in the way it operates. Griffin pf. at 17; Allen pf. at 8; findings 24-47, above.

g. Reasonably Balanced System of Risks and Rewards (§ 218d(a)(7))

62. The Plan establishes a reasonably balanced system of risks and rewards that encourages the Company to operate as efficiently as possible using sound management practices, by reducing the Company's cost of capital, flowing this beneficial impact through to customers, and by creating cost control incentives. Griffin pf. at 11, 17; Hevert supp. pf. at 4-5; exh. GMP-AJK-4 at 3-6; Allen pf. at 8; findings 24-47, above.

h. Reasonable Opportunity to Earn a Fair Rate of Return (§ 218d(a)(8))

63. The Plan provides a reasonable opportunity to earn a fair rate of return by providing for periodic rate adjustments to reflect differences between target and actual costs, subject to the Power Efficiency and Earnings Sharing Bands. Griffin pf. at 16; findings 24-47, above.

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i. Impact on Accounting (§ 218d(m)(1))

64. The Plan will not have an adverse impact on the Company's eligibility for rate-regulated accounting in accordance with generally accepted accounting standards, because the Company will continue to have an opportunity to recover its costs and because rates will continue to be based on costs. Griffin pf. at 18; findings 24-47, above.

j. Preserve the Availability of Equity and Debt Capital Resources (§ 218d(m)(2))

65. The Plan reasonably preserves the availability of equity and debt capital resources to the Company on favorable terms and conditions, because Wall Street analysts and rating agencies strongly favor power adjustment clauses that permit rates to reflect costs on a regular basis, and because the Company's risks are reduced. Griffin pf. at 17; Allen pf. at 5; findings 24-47, above.

k. Reasonable Sharing of Savings with Ratepayers (§ 218d(b))

66. The Plan provides that any savings resulting from the Plan will be shared with ratepayers through the combination of the three adjustments and the bands included in the Earnings and Power Adjustors. Griffin pf. at 17; Allen pf. at 8; findings 24-47, above.

B. Discussion

The Plan proposed by GMP is the first alternative regulation plan for an electric utility in Vermont. [FN34] Alternative regulation for electric and gas utilities is authorized by Section 218d of Title 30. That section also delineates a series of findings that the Board must make before it can approve an alternative regulation plan. Specifically, Section 218d(a) requires that the Board find that an alternative regulation plan will:

> (1) establish a system of regulation in which such companies have clear incentives to provide least-cost energy service to their customers;
>
> (2) provide just and reasonable rates for service to all classes of customers;
>
> (3) deliver safe and reliable service;
>
> (4) offer incentives for innovations and improved performance that advance state energy policy such as increasing reliance on Vermont-based renewable energy and decreasing the extent to which the financial success of distribution utilities between rate cases is linked to increased sales to end use customers and may be threatened by decreases in those sales;
>
> (5) promote improved quality of service, reliability, and service choices;
>
> (6) encourage innovation in the provision of service;
>
> (7) establish a reasonably balanced system of risks and rewards that encourages the company to operate as efficiently as possible using sound management practices; and
>
> (8) provide a reasonable opportunity, under sound and economical management, to earn a fair rate of return, provided such opportunity must be consistent with flexible design of alternative regulation and with the inclusion of effective financial incentives in such alternat- ives.

Under subsection (m), in the case of an investor-owned utility such as GMP, we must also find that the plan will:

(1) not have an adverse impact on the electric com-

> FN34. We have previously authorized alternative regulation plans for Verizon New England Inc., d/b/a Verizon Vermont and Vermont Gas Systems. *Investigation into an Alternative Regulation Plan for New England Telephone* , Dockets 6167/6189, Order of 3/24/00; *Investigation into Successor Incentive Regulation Plan for Verizon*, Docket 6959, Orders of 9/26/05 and 4/27/06; *Petition of Vermont Gas Systems, Inc. for approval of an alternative regulation plan* , Docket 7109, Order of 9/21/06.

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pany's eligibility for rate-regulated accounting in accordance with generally accepted accounting standards if applicable; and

(2) reasonably preserve the availability of equity and debt capital resources to the company on favorable terms and conditions.
In addition, subsection 218d(b) required that "if savings result from alternative regulation, the savings shall be shared with ratepayers as determined by the board."Finally, Section 218d(h) permits the Board to establish, by rule or order, standards by which to assess the effectiveness of alternative regulation plans.

Alternative regulation, while authorized by statute, is an option, not a requirement. As we have observed in the past, any meaningful analysis of alternative regulation must consider the opportunity cost of continuing under additional regulation. [FN35]This means that we should expect that both the Company *and* its customers will benefit from alternative regulation.

FN35. *See* Docket 6959, Order of 9/26/05 at 23.

Here, GMP argues that its Plan will benefit both itself and its customers. In particular, GMP states that it proposed the Plan in order to provide the following customer benefits: (1) avoid the drain on resources resulting from traditional rate cases, which are inefficient, lengthy and expensive; (2) reduce the uncertainty associated with the timing and magnitude of rate changes; (3) reduce the mismatch between costs and rates due to regulatory lag; (4) provide improved cost reduction incentives; and (5) reduce rates through the incorporation of a lower **ROE**. [FN36]

FN36. Griffin pf. at 8.

CLF and IBM challenge numerous aspects of the Plan, arguing that:

• the Plan will not provide adequate incentives to control costs;

• the Plan does not present a balanced system of risks and rewards that encourages GMP to operate as efficiently as possible;

• the Plan does not adequately reduce the link between sales and earnings;

• the Plan provides insufficient incentives to promote renewable energy;

• the Plan will increase rate volatility;

• the Plan results in inaccurate price signals and the signals provided are less than those under traditional regulation;

• the rates may not be just and reasonable because the Plan does not provide an adequate opportunity to review price changes; and

• the Plan should be modified so that the 10 percent of Component B power costs that are excluded from the Power Adjustor should also be excluded from the Earnings Sharing Adjustor.

We have considered the parties' comments and concluded that the Plan as proposed by GMP and the Department is reasonable and should be approved. The Plan offers several benefits. It will, over time, reduce some of the time and expense associated with litigated rate adjustments. Instead of the traditional filing of rate increases that often lead to contested-case proceedings, GMP will have more frequent, but also more limited rate adjustments. The Board, Department, and parties will have increased workload to evaluate these filings. But we expect that the overall burden will be less than under traditional regulation, while still ensuring that rates are just and reasonable. In this regard, GMP's agreement to review by an independent third party should help address some of the workload and timing considerations. [FN37]

FN37. Exh. GMP-AJK-3 at 3.

The Plan also will help GMP meet the long-term energy goals of the state - namely the provision of high quality service at least-cost. One of the major benefits of the Plan is the likelihood that it is likely to improve GMP's financial ratings and credit worthiness. This will en-

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hance GMP's ability to pursue a broad range of options to replace the large power contracts that will begin to expire in 2012. It should also reduce GMP's cost of capital, producing savings that can be passed on to ratepayers. [FN38]

FN38. Allen pf. at 5.

For many of the statutory criteria, the evidence is undisputed. No party questions the fact that it (1) will have no effect on accounting, (2) will not adversely affect GMP's access to credit (which is likely to be enhanced), (3) will lead to the delivery of safe and reliable service, (4) will promote improved quality of service, reliability, and service choices, (5) results in sharing of savings, and (6) will encourage innovation. In the following sections, we consider each of the objections raised by IBM and CLF.

1. Incentives to Provide Least-Cost Services

Section 218d(a)(1) requires that the Board find that an alternative regulation plan establish a system of regulation providing companies with "clear incentives to provide least-cost service to their customers."IBM and CLF both claim that the Plan will not provide sufficient incentives to control costs. To the contrary, IBM asserts that GMP's incentive to manage costs would be substantially reduced. IBM argues that this incentive occurs because lax management will lower earnings, thus potentially triggering an upwards rate adjustment through the Earnings Sharing Adjustor. [FN39]In addition, IBM contends that GMP would have fewer earnings at risk than under traditional regulation. IBM also avers that GMP would have the incentive to understate sales growth and either overstate costs or increase discretionary expenditures to take advantage of the rate adjusters and obtain higher rates. Finally, IBM suggests that the Plan has insufficient safeguards to protect against these incentives. [FN40]

FN39. IBM Brief at 8.

FN40. *Id.* at 8-10.

CLF argues that the absence of a mechanism decoupling sales and earnings fails to create a system in which GMP provides least-cost service. CLF maintains that GMP has a continued disincentive to encourage efficiency. In addition, CLF argues that the unfair balance of risks and rewards means that there are insufficient incentives for least-cost service. [FN41]

FN41. CLF Brief at 12-13.

GMP responds that the Earnings Sharing Band and the Power Efficiency Band create strong incentives to control costs because GMP cannot know how its earnings and power costs will fall. In addition, GMP asserts that the asymmetrical Earnings Sharing Band, the ability of the Board to open an investigation, and the fact that 10 percent of the Component B power costs are not recovered creates adequate incentives.

In order to meet the statutory mandate, the Plan does not need to contain direct measures that will insure least-cost service, but instead must create the appropriate incentives. Thus, although the Plan lacks any direct requirements, we conclude that the Plan contains adequate incentives for GMP to control its costs, thereby providing service at just and reasonable rates and advancing the goal of providing least-cost services. Several features of the Plan create this incentive. GMP can benefit by increasing its earnings. Under the Plan, to the extent that GMP can increase its earnings above the 10.25 percent authorized **ROE**, the Company can retain the bulk of the excess earnings. GMP thus has an incentive to reduce costs to take advantage of this feature. [FN42]In addition, while some increases in GMP's power costs are passed on to ratepayers through the Power Adjustor, in each quarter, GMP must absorb the first $300,000 of additional Component B costs, as well as 10 percent of any greater amount. Essentially, this means that smaller variations in power costs will not be automatically flowed through in rates, providing GMP with a strong incentive to control these costs, thereby enhancing its earnings. [FN43]

FN42. By contrast, under the settlement approved in Docket 6867, GMP had to return all earnings in excess of its allowed **ROE**. *Investigation into Memorandum of Understanding*

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between GMP and DPS, Order of 12/22/03 at 43.

FN43. Obviously, larger quarterly changes would still be captured by the Power Adjustor. However, these may reflect market shifts or weather and demand impacts that are harder for GMP to predict or manage.

We are also persuaded that, for the most part, unpredictability will make it difficult for GMP to manage its earnings as precisely as IBM suggests. Certainly, a degree of uncertainty exists for power costs, even in the shorter term. GMP has greater control over its operational costs and can accelerate or defer certain projects to manage its returns. But we expect that GMP will be unable to manipulate its costs so precisely that it can obtain unwarranted rate increases or earn excessive amounts. Absent such an ability to predict its earnings and how those earnings will be affected by the Power Efficiency Band and Earnings Sharing provisions, the Plan should provide incentives for GMP to operate efficiently, so as to optimize earnings. Such efficient operation should also benefit ratepayers as the lower cost structure is flowed through in base rates.

We also note that the Board retains jurisdiction to monitor the Plan and investigate rate changes through the adjustors. If it appears that GMP has more ability to take advantage of unintended incentives than we expect, the Board can investigate proposed rate adjustments to determine whether they are just and reasonable. In addition, the Board retains jurisdiction under 30 V.S.A. § 218d(i) to investigate the Plan while it is in effect and can then terminate it or modify the terms and the conditions.

2. Balanced Risks and Rewards

CLF argues that the Plan fails to fairly balance the risks and rewards and, thereby, fails to encourage the Company to make sound decisions. CLF asserts that a fair plan must create a system of incentives and price signals that encourage good decision-making; one that simply passes through costs, says CLF, fails to meet this standard. CLF maintains that GMP should bear at least a portion of the risk associated with costs that are within the Company's control. CLF also contends that the opportunity for later investigation is insufficient to remedy this imbalance since it is really unchanged from the present. [FN44]

FN44. CLF Brief at 10-11.

IBM also contends that the Plan is imbalanced in that it inappropriately shifts risk to customers. From IBM's perspective, ratepayers now bear the risk of inaccurate utility operation cost forecasts, even though these are often within the Company's control. IBM maintains that GMP is more capable of managing these risks, primarily associated with power supply, than are the Company's customers. IBM argues that the Board should instead require GMP to maintain more of the risk, including that associated with sales volatility. [FN45]

FN45. IBM Brief at 7.

GMP responds that most of the arguments raised by IBM and CLF focus on the allocation of risks and rewards between the Company and customers, rather than on the balance of risks and rewards. As a result, GMP maintains that these arguments are irrelevant. GMP contends that CLF is wrong when it takes the position that the Plan creates insufficient incentives for GMP to control costs. GMP also asserts that IBM's view that risks should be assigned based upon the ability to diversify risk is unsupported by any Board precedent or regulatory principle. Finally, GMP asserts that, to the extent that the Plan passes additional short-run risk to customers, this risk shift is outweighed by the long-run decrease in risk to the Company, which under the Plan will produce savings for customers. [FN46]

FN46. GMP Reply Brief at 4-6.

Under Section 218d(a)(7), we must determine whether the Plan establishes a reasonably balanced system of risks and rewards. As GMP asserts, this criteria focuses primarily (but not exclusively) on whether an alternative regulation plan is structured so that the overall balance is reasonable and promotes efficient operations.

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Here, as we discuss in the previous section, we find that the Plan creates reasonable incentives for GMP to control its costs and provide least-cost services.

It is, however, also appropriate to consider the overall balance of risks and rewards between GMP and its customers. This mandate derives in part from Section 218d(a)(7) - if we were to interpret this provision as narrowly as GMP argues (*i.e.*, limited to the question of whether the incentives and risks assigned to GMP encourage efficient operation), it would be largely redundant with the criteria in Section 218d(a)(1) (relating to the creation of incentives to least-cost energy service). In fact, GMP's arguments as to how the two criteria have been met are essentially the same. More significantly, if the balance struck between GMP and its ratepayers is not reasonable, it is unlikely that we could find that the Plan provided just and reasonable rates to all classes of customers.

The Plan proposed by the Department and GMP clearly shifts a large element of financial risk from GMP's shareholders to ratepayers - in fact, as the Department explained, strengthening the connection between costs and rates is one of the goals of the Plan. [FN47]However, at the same time, the elements of the Plan are likely to provide ratepayers both short and long-term benefits. Most directly, the Plan incorporates a lower **ROE** than would be used to set rates under traditional regulation. The Power Adjustor, while passing through some costs, also incorporates a Power Efficiency Band (for which GMP retains the risk) as well as a sharing of power costs in excess of that band. [FN48]Moreover, the Plan does not flow through only rate increases to customers; to the extent that wholesale costs are lowered or other cost savings are derived, these will also be passed on to consumers. [FN49]

FN47. Allen pf. at 2.

FN48. Smith reb. pf. at 18-20; exh. GMP-AJK-4 at 3-6.

FN49. Exh. GMP-AJK-4 at 3-6; Hevert supp. pf. at 4-5; Smith reb. pf. at 18.

Over the long-term, the approval of the Plan will reduce the risk of credit rating downgrade, which could entail additional costs for ratepayers. It should also enable GMP to pursue a broader range of resource options, which could provide significant value. [FN50]

FN50. Tr. 9/27/06 at 83-84 (Allen).

We do not accept IBM's argument that the Plan is flawed because it does not allocate risk on the basis of whether customers or the Company are in a better position to manage the risk. IBM has not demonstrated that such a risk allocation is reasonable nor has it cited any regulatory principle for adopting such an allocation, particularly since it is inconsistent with long-standing practice. Even though GMP now manages the risk associated with power costs, the actual financial risk is now borne by ratepayers. GMP enters into hedging arrangements to protect itself from wholesale price variability. And, as we discussed above, GMP purchases outage insurance against the possible increased replacement power costs arising from an outage at Vermont Yankee. These costs are included in the cost-of-service and paid for by ratepayers. Thus, the costs associated with power cost risk management now rest with ratepayers. The Plan would replace the fixed costs of hedging arrangements with the actual costs of the power. We expect that, although they may see more short-term variability, ratepayers will pay lower net costs as a result.

It is difficult to determine whether the likely intangible benefits of the improved financial status will be greater than the increased costs and risks that consumers will now bear. In particular, it is not clear that the 50-basis-point adjustment to the **ROE** is balanced with the shift in risks from GMP's shareholders to ratepayers. GMP and the Department make clear their view that the Plan as a whole is beneficial. After consideration of the parties' arguments, we conclude that the risk/reward allocation in the MOU and Plan is reasonable. In reaching this conclusion, we are mindful of the Department's assessment that, on balance, the Plan is a positive one for ratepayers. [FN51]In addition, the Plan assures that we retain the jurisdiction to review costs, if necessary, through an investigation under Section 227(b), or to investigate the Plan itself under Section 28d(i).

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FN51. Allen pf. at 4.

We also find value in allowing an opportunity to determine whether alternative regulation will, in the long-run, provide greater benefits to ratepayers. As we discussed elsewhere in this Order, we expect that the Plan will provide incentives that will benefit ratepayers as well as the Company. However, we intend to closely monitor GMP's performance under the Plan to evaluate whether the balance of risks and rewards remain fair.

3. Incentives to Advance State Energy Policy

CLF contends that the proposed Plan does not meet the statutory requirements of Section 218d(a)(4). This section requires that an alternative regulation plan offer incentives for innovations and improved performance that advance state energy policy, such as increasing reliance on renewable energy and decreasing the linkage between utility earnings and sales to customers. According to CLF, the Plan offers no new incentives for efficiency or renewable energy. [FN52]In addition, CLF maintains that the plan fails to separate utility profits from the volume of sales. CLF observes that two elements of the Plan - the cap on the Company's **ROE** and the earnings sharing mechanism - may reduce this linkage; but to be effective, a link must actually affect decisions or investments to meet the statutory criteria. Instead, CLF contends that an effective plan must make GMP's profits neutral to changes in sales volumes. [FN53]

FN52. CLF Brief at 5.

FN53. CLF Brief at 6.

GMP replies that the statute does not require that the connection between sales and earnings be decoupled. Instead, GMP asserts that the statute only requires that there be an incentive to reduce the linkage between earnings and sales, not necessarily a reduced linkage itself. [FN54]The record, GMP argues, demonstrates that the Plan will result in some reduction of the linkage between earnings and sales, a point that GMP says even CLF concedes. GMP also maintains that CLF has provided insufficient evidence to support establishment of a mechanism that stabilizes GMP's revenue per customer.

FN54. GMP Reply Brief at 8.

This Board has consistently promoted actions that advance state energy policies, particularly investments in efficiency and renewable energy. Thus, we agree with the concerns that underlie CLF's testimony. Any Plan must, both as a matter of law, and as an essential element of sound least-cost energy service, continue to provide incentives for efficiency and renewable energy. Nonetheless, the statute does not mandate either decoupling or specific incentives for the development of renewable energy. Rather, Section 218d(a)(4) mandates that the Plan offer "incentives for innovations and improved performance that advance state energy policy."Here, we find that the criteria has been met. As we have discussed throughout this Order, the Plan will create incentives for GMP to reduce its costs and improve its performance. The Plan places GMP in a sound financial situation which may assist the Company in pursuing investments in renewable energy. We also note that GMP recently introduced a renewable rider to its tariffs that provides financial support for new renewable generation, with a preference for Vermont-based generation. [FN55]

FN55. Brown pf. at 4.

The evidence also shows that the proposed Plan would reduce the linkage between GMP's earnings and the level of sales in several ways. GMP will adjust its base rate annually. This will have the effect of capturing any increased sales that may have occurred in the revenue requirement; a higher sales volumes adjustment will serve to essentially recalibrate the billing determinants. In addition, to the extent increased sales result in increased earnings, the impact would be mitigated through the Earnings Sharing Adjustor. [FN56]The sales-earnings linkage is also reduced relative to traditional regulation, because loads are forecast in the base rate adjustments, and therefore the impact of expected sales increases are captured and flowed through to the customer. [FN57]Although these steps do not represent the full decoupling of sales and earnings that CLF seeks,

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they are adequate to meet the mandate of Section 218d(a)(4) which requires only that there be an incentive to reduce the linkage between earnings and sales, not that any linkage must be eliminated. [FN58]

FN56. Smith reb. pf. at 4-6.

FN57. Smith reb. pf. at 5-6; Allen pf. at 7.

FN58. Smith reb. pf. at 3; 30 V.S.A. § 218d(a)(4).

Furthermore, CLF has also not demonstrated how state energy policy would be more greatly advanced by further severing the linkage between earnings and sales. In general, reducing the linkage provides an additional incentive to a company to operate in a cost-effective manner as its earnings would be unaffected. Decoupling thus removes a disincentive to undertake investments that would lower earnings, such as energy efficiency. In Vermont, however, statewide energy efficiency is delivered by the Energy Efficiency Utility; the Board has removed the legal obligation for utilities to operate energy efficiency programs. Thus, the Company has limited ability to undermine efficiency efforts; in light of this role, it is unclear what additional benefits would be provided by a broader decoupling such as that proposed by CLF. [FN59]

FN59. Smith reb. pf. at 6-7; Allen pf. at 7.

4. Rate Volatility and Price Signals

IBM asserts that the Plan will "significantly" increase rate volatility for customers. According to IBM, rates could be adjusted up to six times per year. [FN60]In addition, IBM contends that since GMP can adjust its power costs (which represent approximately 80 percent of its cost of service quarterly) the rate volatility will be significant. IBM argues that this increased price volatility is particularly problematic because it is based upon neither prevailing market conditions nor GMP's actual cost-of-service. This disconnection with the cost-of-service occurs because the rate adjustment is based upon past costs, unlike rate proceedings in which recovery of historical over or under-collections would be barred. Moreover, IBM maintains that the fact that the adjustments would be based upon a uniform percentage adjustment to all rates means that the rates will become less connected to the cause of those costs. [FN61]

FN60. Gorman pf. at 40-41; IBM Brief at 2.

FN61. IBM Brief at 2-3; Gorman pf. at 43.

GMP responds that the Plan will result in less price volatility. GMP argues that even though rates may be adjusted more frequently, consideration of price volatility must also consider both the magnitude and uncertainty of change. [FN62]Under the Plan, contends GMP, the rate changes will be more certain than under traditional rate-of-return regulation, will be smaller than under such regulation, and will be based upon formulaic methodologies. [FN63]GMP also submits that price signals under the Plan will be more accurate because rate changes are more frequent, the Plan greatly reduces the lag between cost incurrence and rate implementation and because, unlike traditional regulation, rates will be adjusted to correct inaccurate projections. [FN64]

FN62. GMP Brief at 18; Kvedar reb. pf. at 4.

FN63. GMP Reply Brief at 2-3.

FN64. GMP Brief at 21; Smith reb. pf. at 9-10.

The dispute between GMP and IBM on whether greater frequency or greater magnitude constitutes more volatility is a semantic one that we do not need to resolve. It is undisputed that the Plan will change the manner and timing of rate adjustments; changes in rates will become more frequent. Over the past 10 to 15 years, GMP's customers have seen less than one rate increase per year. Instead, they will experience four rate adjustments annually. [FN65]For many customers, they will perceive the result as greater volatility. At the same time, as GMP points out, it is likely that many of these adjustments will be smaller than those traditionally experienced by customers. GMP will be able to pass on smaller changes in costs, which would otherwise not be recovered until the next rate proceeding.

FN65. Exh. GMP-AJK-4 at 1, 3, 5; Kvedar reb.

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pf. at 4.

As a part of the overall Plan, however, we find that change in the way costs are passed on to ratepayers is reasonable. The Plan's major benefits, including GMP's improved financial status, are sufficient at this time to outweigh any negative consequences of these more frequent, but smaller, rate adjustments. In particular, the regular rate adjustments will help GMP pass through the potentially significant power cost changes that are occurring in the wholesale power market. This wholesale price volatility could have negative implications on GMP's financial performance and ability to access capital. Allowing GMP to pass through these costs to ratepayers at this time will help ratepayers by keeping GMP on a sound financial footing. It also will enable GMP to reduce the need to enter into hedging agreements - which can be very costly to the Company and to ratepayers - to mitigate the effects of the wholesale market. [FN66]

FN66. Allen pf. at 3-5.

We also conclude that the Plan does not inappropriately alter the price signals that ratepayers will receive. We are unpersuaded by IBM's contention that the Plan distorts price signals due to the fact that rate adjustments are based upon a percentage of existing rates. The implementation of rate changes through an across-the-board percentage adjustment is the manner in which electric companies have traditionally implemented such changes. [FN67]Only when the Board subsequently performs a rate design investigation is this practice altered, and then only after the rate design proceeding is completed. Thus, to the extent the use of percentages may result in some minor distortion of cost-based rates, that is unchanged from current practice. Continuation of this practice is reasonable in the absence of a rate design proceeding. [FN68]Moreover, use of a kWh charge in the Power Adjustor is also appropriate; the cost changes that are captured by the adjustor largely reflect energy costs. [FN69]

FN67. *See* Docket 5983 Order at 267; Docket 6107 Order at 121; tr. 9/27/06 at 32-33 (Gorman).

FN68. Smith reb. pf. at 10-11. In fact, IBM's witness agreed that, absent a rate design change, a uniform percentage increase may be reasonable. Tr. 9/27/06 at 32-33 (Gorman).

FN69. Smith reb. pf. at 10.

We also do not find convincing IBM's argument that the rate adjustments under the Plan will distort price signals because they are based upon past costs rather than forward-looking costs. Neither traditional ratemaking nor the Plan are structured to send fully accurate price signals to consumers. Under traditional ratemaking, power costs are based upon test year costs, adjusted for known and measurable changes. This means that known adjustments to power costs are flowed through into rates, but projections about market prices may not be captured. Moreover, in the absence of real-time pricing, the price signal consumers receive through rates may bear little relationship to GMP's actual marginal price for power. Thus, the signal under traditional regulation is at best imprecise.

The Plan, while still not sending accurate real-time price signals, is likely to provide better signals. Power cost changes will be flowed through more quickly. While these changes are based upon past events, as IBM suggests, they also reflect more recent power cost data than did the rates set based upon the traditional methodology. The reduction in the time lag means that inaccurate projections are corrected more quickly. [FN70]

FN70. Smith reb. pf. at 9-10.

5. Just and Reasonable Rates

IBM argues that the Plan may not result in just and reasonable rates as required by Section 218d(a)(2). According to IBM, the three rate adjustments provided under the Plan must be reviewed by the Board and parties under short time frames - 60 days for Base Rate Adjustor and 45 days for the Power and Earnings Sharing Adjustors. [FN71]IBM views these time frames as insufficient. IBM also contends that the review of the base rate filings by the consultant as specified in the MOU is not adequate since other customers and parties are also en-

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titled to a fair opportunity to review the filing. IBM also maintains that the opportunity to suspend the base rate adjustment is not adquate; formal investigation of rates will not result in a decrease in administrative costs - one goal of the Plan - and suspension does not apply to the Earnings and Power Adjustors. [FN72]

FN71. IBM Brief at 10.

FN72. IBM Brief at 12.

GMP asserts that IBM's arguments fail to take into account the Department's "role as institutional ratepayer advocate." In addition, GMP argues that time periods are reasonable in light of the nature of each of the filings. [FN73]

FN73. GMP Reply Brief at 6-7.

We agree with IBM that the time period for review of the various adjustors is short. Nonetheless, as a part of the overall Plan, we find them reasonable. Unlike a traditional rate proceeding, we expect that each of the rate filings will be more limited in scope. For example, the Power Adjustor encompasses only power costs. Similarly, the Earnings Sharing Adjustor has a narrow scope. These filings will thus be more manageable in a limited period of time. In addition, the MOU provides that the Department will have a consultant to review the annual base rate adjustment. [FN74]This includes the forecasts and the impact of any variations between forecasts and actual loads will be addressed in the Power and Earnings Sharing Adjustors. [FN75]Although this may not aid consumer groups or IBM, it will provide an additional level of review. We have also seen that a shorter review period can work if tailored appropriately. Under the Memorandum of Understanding in Docket 6867, GMP and the Department agreed to rate increases of 1.9 percent in 2005 and 0.9 percent in 2006, with GMP submitting the tariff filings only 60 days in advance of implementation. To comply with Vermont law, however, it was necessary that these filings be subject to review and investigation and that they be fully supported by a cost-of-service. No party indicated that the 60-day period for review was inadequate. Since we expect that the annual base rate adjustment will be of similar scope, it is reasonable to infer that parties will have sufficient time now.

FN74. Exh. GMP-AJK-3 at 3.

FN75. Kvedar reb. pf. at 6.

6. Calculation of the Earnings Sharing Adjustor

IBM asserts that if the Board approves the Plan, it should modify the Earnings Sharing Adjustor. Under the modified Power Adjustor in the revised Plan, only 90% of Component B costs in excess of the $300,000 Power Efficiency Band are flowed through to rates each quarter, with the remaining 10 percent absorbed by GMP. IBM contends that because the Power Adjustor and Earnings Sharing Adjustors interact, any amounts excluded from the Power Adjustor, including the 10 percent of Component B costs, are potentially collected through the Earnings Sharing Adjustor. As a remedy, IBM asks that we modify the Earnings Sharing Adjustor to require GMP to absorb the excluded 10 percent of Component B costs. [FN76]

FN76. IBM Brief at 13-15.

GMP contends that because of the potentially large lag time between power costs being incurred and the calculation of the Earnings Sharing Adjustor, GMP cannot accurately predict the effect of the 10 percent Component B exclusion on its earnings. Thus, the incentives inherent in the 10 percent exclusion are unaffected. GMP also argues that, to the extent that IBM is correct, GMP must still incur the carrying costs between the time the power costs are incurred and the later collection in the Earnings Sharing Adjustor.

We are not persuaded that we must modify the Earnings Sharing Adjustor as IBM recommends. The exclusion of Component B costs is intended to force GMP to retain a greater proportion of the risk of rising power costs (primarily energy) than would GMP's original proposal (although less than under traditional regulation). This risk retention by GMP would provide greater incentives for the Company to manage its power resources cost-effectively. IBM is correct that, under certain circum-

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stances, excluded power costs could depress earnings and lead to an increase in rates through the Earnings Sharing Adjustor that would (at least in part) offset the excluded costs. However, GMP's ability to accurately forecast its annual Earnings Sharing adjustment means that for most of the year, the Company's incentives to cost-effectively manage its power costs will be unchanged; GMP cannot know in the first half of the year, for example, that excess power cost increases that lead to an exclusion will ultimately be recovered through rate adjustments. [FN77]Thus, the interrelationship of the exclusion and the Earnings Sharing Adjustor will not adversely affect the incentives. [FN78]

FN77. Smith reb. pf. at 20.

FN78. We do not, however, rely upon GMP's argument that the Plan is fair because the Company would incur carrying costs. It is unlikely that this fact would have any impact on GMP's incentives or actions.

VI. CONCLUSION

For the reasons set out above, we approve the MOU between the Department and GMP and authorize an increase in retail rates of 9.09 percent, effective January 1, 2007. With this increase, GMP's rates will be just and reasonable.

We also approve the alternative regulation plan set forth in the MOU. Over its term, the alternative regulation plan has the promise of improving GMP's financial status, while simultaneously benefitting ratepayers.

Our review of the alternative regulation plan in this proceeding has been limited to the unique circumstances of GMP, and should not be interpreted more broadly as endorsing a similar alternative regulation plan for any other Vermont utility. Whether a similar plan would be appropriate for another utility is a determination that must be made based on the facts relevant to that particular utility. For this reason, and as the MOU provides, today's Order should not be construed as having any precedential effect, except as necessary to ensure GMP's performance under the MOU or to enforce an order of the Board resulting from the MOU.

VII. ORDER

IT IS HEREBY ORDERED, ADJUDGED AND DECREED by the Public Service Board of the State of Vermont that:

1. The Memorandum of Understanding ("MOU") between Green Mountain Power Corporation ("GMP" or the "Company") and the Vermont Department of Public Service ("Department") is approved.

2. The Company is entitled to rates that will produce additional retail revenues of $19,024,000 or 9.09% above existing base rates for service rendered on or after January 1, 2007.

3. GMP's alternative regulation plan ("Plan") is approved to take effect on February 1, 2007.

4. GMP shall file tariffs in compliance with this Order by December 28, 2006.

5. The Service Quality and Reliability Plan filed on September 28, 2006, is approved.

6. By November 1, 2006, GMP shall submit to the Department a proposal for documenting and reporting the six rate filings required under the Plan including but not limited to power supply costs, plant additions and capital expenditure plans and budgets in connection with base rate, power adjustor and earnings sharing adjustor changes, and will incorporate any revisions to its proposal thereafter proposed by the Department or provide a detailed explanation for not doing so. Any unresolved disputes shall be submitted to the Board for resolution.

7. Under the MOU, the Department will retain, at the Company's expense and subject to the Company's reasonable consent, an independent third party with accounting and rate-making expertise ("Third Party") to review each base rate filing under the Plan for (1) accuracy, (2) completeness, (3) compliance with traditional rate-making and existing Board Orders regarding cost-of-service filings including the calculation of regu-

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lated earnings and (4) consistency with the Company's actual costs and the Plan. The Third Party shall file a report with the Board and Department at the time the base rate filing is submitted to the Board.

8. The Company shall submit, within 30 days of this Order, a sample of each type of filing to be made under the Plan and the Department shall provide any comments within 30 days thereafter. GMP shall consider in good faith any changes to the filing formats under the Plan as the Department deems to be reasonably necessary to complete an efficient and meaningful review of the filings due under the MOU. Any irresolvable issues shall be referred to the Board for resolution.

9. GMP shall collaborate in good faith with the Department on its plans concerning. customer information regarding the Plan, including Customer Service Representative training, and the timing and substance of customer communications.

10. GMP shall collaborate in good faith with the Department to develop tariffs providing for an annual, fixed-unit-price service to commence no later than November 1, 2007.

11. By June 30, 2007, GMP and the Department shall jointly develop and submit for Board approval criteria to be used in assessing the Plan's effectiveness at the end of its initial term. Neither the Company nor the Department shall be bound to support termination or extension of the Plan beyond its initial term based solely upon the criteria so developed.

12. GMP shall accrue an annual reserve of $315,000 to be used to offset the costs of any unscheduled outages relating to the Vermont Yankee Nuclear Power Station. The Company shall notify the Board and Department when and if it becomes necessary to use all or part of the reserve.

13. Within 180 days of this Order, GMP shall introduce a plan to provide large commercial and industrial customers an option to participate in the procurement of power supply to meet individual customer loads.

14. Not later than June 30, 2008, and June 30, 2009, the Company shall file a report with the Board and Department evaluating the effectiveness of the Plan's performance in achieving the goals of 30 V.S.A. § 218d. In advance of filing the reports, the Company shall confer with the Department with respect to the measurement criteria to be used in the reports.

15. GMP shall describe the Plan in a separate mailing to customers at least one month prior to the first rate adjustment under the Plan and shall work with the Department in the development of customer communications and materials to be provided to customers.

Dated at Montpelier, Vermont, this 22nd day of December, 2006.

James Volz

David C. Coen

John D. Burke

OFFICE OF THE CLERK FILED: December 22, 2006
ATTEST: Susan M. Hudson Clerk of the Board

END OF DOCUMENT

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ATTACHMENT M

1053-E-549

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA
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ORDER

September 28, 2009

FORMAL CASE NO. 1053, IN THE MATTER OF THE APPLICATION OF THE POTOMAC ELECTRIC POWER COMPANY FOR AUTHORITY TO INCREASE EXISTING RETAIL RATES AND CHARGES FOR ELECTRIC DISTRIBUTION SERVICE, Phase II, Order No. 15556

I. INTRODUCTION

1. By this Order, the Public Service Commission of the District of Columbia ("Commission") approves the Potomac Electric Power Company's ("Pepco" or "Company") Bill Stabilization Adjustment ("BSA"), as modified, to become effective on November 1, 2009. Pepco shall file a compliance filing within 10 days from the date of this Order and shall implement the BSA in accordance with the directives set forth in this Order.

II. BACKGROUND

2. As part of its most recent distribution rate case, Pepco proposed a revenue decoupling adjustment, the BSA, designed to decouple revenues from the variation in kWh sales, allowing the Company to adjust its base (delivery) rates to reflect actual changes in the revenue it collects on a per customer basis from adjusted test-year levels. The BSA is intended to account for changes in usage due to variations in weather, customer response to price increases or energy-efficiency programs. On January 30, 2008, the Commission issued its Opinion and Order on Pepco's rate case.[1] In that Order, the Commission agreed with the BSA mechanism, in concept,[2] but determined that Pepco's proposed BSA would be considered in a Phase II proceeding to address whether and how the BSA can be implemented consistent with the relevant statutory requirements regarding utility rate changes.[3] In its decision, the Commission raised several questions regarding the BSA implementation process in light of the statutory requirements of D.C.

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1 *Formal Case No. 1053, In the Matter of the Application of the Potomac Electric Power Company For Authority To Increase Existing Retail Rates and Charges for Electric Distribution Service*, Order No. 14712 (January 30, 2008) ("*F.C. 1053*").

2 Order No. 14712, ¶ 351.

3 *Id.*, ¶¶ 352-354.

Code §§ 34-909(a), 34-908, and 34-910(a).[4] Order No. 14740, issued February 28, 2008, initiated Phase II of Formal Case No. 1053.[5]

3. By Order No. 15042, the Commission determined that it possesses statutory authority to implement Pepco's BSA proposal. In addition, the Commission determined that the BSA formula is a rate and, once it is approved, any periodic adjustments made pursuant to the formula do not constitute a change in the rate itself and would not trigger the notice and hearing provisions under the applicable D.C. Code provisions. However, the Commission went on to state that the record was, as yet, insufficiently developed to make a finding that Pepco's BSA proposal is just and reasonable. As a result, the Commission directed the parties to develop a list of issues that they believe require resolution in this phase of the proceeding. Subsequently, by Order No. 15135, the Commission designated six (6) issues for consideration and established a procedural schedule for the Phase II proceeding.[6]

4. In accordance with the adopted procedural schedule, Pepco submitted Supplemental Direct Testimony on January 30, 2009. The Office of the People's Counsel ("OPC") and the District of Columbia Government, District Department of the Environment ("DDOE") submitted Supplemental Direct Testimony on March 4, 2009. The Apartment and Office Building Association ("AOBA") submitted its Supplemental Direct testimony on March 6, 2009. Rebuttal testimony was filed by Pepco on March 30, 2009. An evidentiary hearing was held on May 11, 2009, to address the six issues and whether Pepco's BSA is just and reasonable.[7] Initial Briefs were filed by Pepco, OPC, AOBA and DDOE and Washington Gas Light Company ("WGL") on May 29, 2009. The same parties, except for WGL, filed Reply Briefs on June 12, 2009.

III. Bill Stabilization Adjustment ("BSA") Overview

Pepco's Initial BSA Proposal

5. As initially proposed, the BSA was to be applied on a quarterly basis to the distribution charge for most customer classes but not to street lighting ("SL") and telecommunications network ("TN") customers. As explained by Pepco witness Bumgarner, the BSA was designed to provide the Company with a stable revenue stream

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4 *Id.*

5 *F.C. 1053,* Order No. 14740 (Feb. 28, 2008).

6 *F.C. 1053,* Order No. 15135 (Jan. 2, 2009).

7 The Commission is vested with authority to set rates that are "just and reasonable." D.C. Code § 34-911 (2001 Ed.). Although there is no formula for determining what constitutes a reasonable rate, courts have defined the lower boundary of the zone of reasonableness as one that is not confiscatory in the constitutional sense, *i.e.,* it must allow the company to earn a fair rate of return on its investment, and the upper boundary as one that is not exorbitant. *See OPC v. Public Service Commission,* 797 A.2d. 719 (rates must fall within zone of reasonableness safeguarding interests of both investors and consumers).

based on the test-year revenue requirement.[8] For each rate class and for each billing month in a given quarter, the approved test-year revenue per customer for each service classification is applied to the number of customers in each billing month to arrive at target quarterly revenue for each service classification, and the difference between the target revenue and the actual revenue forms the basis for the BSA for the following quarter.[9]

6. As proposed, the BSA was to be billed on a per kWh basis, calculated quarterly for each service classification on a per customer basis, and applied with a 10 percent cap on any quarterly adjustment. This cap would produce a charge or credit that would be carried over into a subsequent quarter's adjustment and a "true-up" that will account for over-collections or under-collections in the BSA in prior quarters. The balance from any over-collection or under-collection would be added to the revenue differences to arrive at a final BSA revenue target for each rate class for the current quarter. This revenue target would be divided by the projected sales for the upcoming billing period, and this rate will be compared to 10 percent of the rate class average test year quarterly rate per kWh to determine the final BSA for the quarter.[10]

7. In describing the theory underlying the revenue decoupling provided by the BSA, Pepco's witness Chamberlin explained that, although distribution costs are largely fixed and change little in the short-run as usage levels change, the distribution tariffs have a significant volumetric component.[11] Additionally, changes in sales result from weather, price elasticity, building standards, expanded energy efficiency programs, and changes in appliance efficiency.[12]

8. Chamberlin argued that the existing cost-of-service rate structure provides a strong incentive for utilities to sell as much electricity or gas as possible, and the current rate recovery mechanism does not encourage energy efficiency through demand-side resources, because demand-side resources reduce sales and, consequently, revenues and fixed cost recovery decline. This creates a disincentive for the utility to consider demand-side resources even when they are the lowest cost option.[13]

9. Pepco's witness Morin proposed a return on equity ("ROE") reduction of 25 basis points to reflect the value of the BSA.[14] Pepco also proposed an alternative $2.3

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8 Pepco (H) at 18 (Bumgarner Direct), Phase I. All references to the testimony, exhibits and briefs are from F.C. 1053, Phase II, unless designated otherwise.

9 *Id.* at 19.

10 *Id.*

11 Pepco (G) at 3 (Chamberlain Direct), Phase I.

12 *Id.* at 8.

13 *Id.* at 9.

14 Pepco (B) at 90 (Morin Direct), Phase I.

million "repression adjustment" to account for lower sales resulting from higher Standard Offer Service ("SOS") prices in lieu of the BSA, were the BSA not implemented.[15]

Pepco's Modified BSA Proposal

10. Subsequently, Pepco modified its proposal in response to comments raised by the parties about the time lag involved in the BSA. Pepco indicated that it could provide monthly adjustments, rather than the quarterly adjustments proposed, in order to address concerns about the timing of the BSA adjustment.[16] In addition, in order to address the perceived impact of the BSA on service restoration following major storm service outages, Pepco also proposed to exclude from the BSA lost revenues associated with outages affecting at least 10,000 customers for over 24 hours.[17]

OPC's Position

11. OPC argued that the Commission should reject the BSA because it would shift a significant amount of risk associated with the operation of Pepco's distribution system from the stockholders to the ratepayers and would essentially guarantee Pepco's recovery of its revenue requirement, including a return, regardless of the quality of service it provided.[18] Specifically, OPC argued that the BSA is unlikely to stabilize customers' bills because multiple factors will be at issue, including: the current monthly adjustment to "normalize revenue" and over- or under-recovery of the prior quarter's BSA and any possible carryover from prior months' excess over the cap.[19]

12. OPC's witness Rothschild stated that the BSA is a risk elimination measure, noting that the BSA virtually eliminates the "non-diversifiable" risks to Pepco investors and provides a guaranteed revenue stream.[20] While some non-diversifiable risks would remain, Rothschild argued that the main risk, cost escalations due to general economic conditions, is an inflation risk that is already factored into the cost of high-rated corporate debt, because such inflation would reduce the purchasing power of the stream of payments that debtors make to their lenders.[21] Given the positive financial

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15 Pepco (F) at 20-22 (Browning Direct), Phase I.

16 *Id.* at 7.

17 Phase I Tr. at 380-381; Phase II Tr. at 28.

18 OPC (H) at 4-5 (Larkin Direct), Phase I.

19 OPC (H) at 10-11 (Larkin Direct), Phase I; OPC Brief at 49 citing Phase I Tr. 584:15-585:5.

20 OPC (B) at 8 (Rothschild Supp. Direct).

21 *Id.* at 10.

implications of the BSA, OPC recommended a cost of equity reduction of 100 to 200 basis points.[22]

13. OPC's witness Larkin testified that the BSA might partially circumvent individual customer actions since the BSA will decouple the delivery of kWh from the revenue generated from customers. He explained that if an individual customer desires to conserve energy and reduces his consumption, that reduction in consumption would be circumvented because, if Pepco did not collect the average revenue per customer as calculated by Pepco from the rate case, then the total customer group would have to make up that shortfall in revenue through the BSA.[23]

14. Larkin further argued that, although the basic calculations for the BSA are verifiable, the inputs for those calculations are not.[24] He concluded that, because there is no current demand-side management ("DSM") program the Company is proposing to be implemented in conjunction with the BSA, there is no justification to implement the BSA at this time.[25]

15. However, to the extent the Commission adopts the BSA, OPC recommended that it be applied to all customers except the SL and TN classes.[26]

AOBA's Position

16. AOBA was generally opposed to Pepco's BSA proposal and argued that it is primarily intended to shift risk traditionally borne by shareholders to its District of Columbia customers. AOBA's witness Oliver stated that customers may not see the stability that Pepco promotes as a benefit of the BSA due to the lag in the application of adjustments under the BSA and the effect of other adjustments and that, under certain circumstances, the Company's BSA proposal may have the effect of amplifying the volatility in Pepco's billed charges for distribution service. He explained that the BSA could increase volatility of billed distribution service charges because weather variations could cause past under-collection from decreased usage to adversely impact customers at a future point. [27]

17. While Pepco contended that the BSA will eliminate the disincentive for the Company to promote energy efficiency by decoupling revenues from sales, AOBA's

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22 OPC (A) at 5 (Rothschild Supp. Direct).

23 OPC (H) at (17) (Larkin Direct), Phase I.

24 OPC (H) at 25 (Larkin Direct), Phase I.

25 *Id.* at 28-29.

26 OPC Brief at 32.

27 AOBA Brief at 3-6.

witness noted that several of Pepco's proposed rate design changes were targeted at similar goals. As an example, AOBA cited Pepco's proposed rate design changes for demand-metered non-residential rate classifications, which shift significant cost recovery from usage (kilowatt-hour) charges to demand charges. AOBA further noted that Pepco does not actively promote increased use of electricity and has implemented DSM programs to improve efficiency in the past without the BSA. Witness Oliver argued that this demonstrates that the BSA is not a necessary prerequisite for DSM programs.[28]

18. AOBA's witness Oliver recommended a downward adjustment of at least 50 basis points to the return on equity if the BSA is adopted. He argued that Pepco has indicated that adoption of its proposed price elasticity based adjustment to test-year revenue is unnecessary if the BSA is approved; therefore, it is reasonable to assume that the benefits of the proposed BSA, less the value of the ROE adjustment, should yield a net value that is equal to or greater than the dollar value of the Company's proposed test-year revenue adjustment. Therefore the total value of expected BSA benefits for Pepco shareholders should be at least $4.15 million on an annual basis, and that equated to a 55 basis point adjustment to the Company's ROE.[29]

19. According to AOBA, Pepco's level of commitment to demand-side resources and the importance of that level of commitment are yet to be determined. Oliver noted that Pepco filed the Blueprint Plan, in which it proposed certain demand-side initiatives, but that Blueprint Plan is being addressed in a separate proceeding. AOBA suggested that, given the unbundled nature of Pepco's service in the District of Columbia, the appropriate role for the Company's demand-side initiatives, particularly for large commercial customers, is at best questionable.[30]

20. AOBA also recommended that large commercial customers and Temporary Service customers, as well as the SL and TN customers, should be exempted from the BSA.[31]

WMATA's Position

21. WMATA argued that Pepco can accomplish the decoupling of sales from revenues through rate design and that Pepco's changes in rate design move toward decoupling because they shift a substantial portion of Pepco's fixed costs to customer charges and demand charges. WMATA's witness Foster stated that the BSA is not needed for stability and, in fact, may result in wider fluctuations from quarter to quarter. He argued that the Budget Billing Plan, already available to Pepco's residential customers, allows customers to pay their yearly costs in equal monthly installments and,

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28 AOBA (A) at 22 (Oliver Direct) Phase I.

29 AOBA Brief at 7; AOBA (A) at 65 (Oliver Direct).

30 AOBA (A) at 28 (Oliver Direct) Phase I.

31 AOBA Brief at 16.

therefore, there is no benefit of bill stability from the BSA since Pepco's customers may already choose to have a set monthly electric bill.[32]

WGL's Position

22. WGL supports the concept of a decoupling mechanism but does not believe that a downward adjustment to return on equity is necessary when weather risk is already factored into the return of equity analysis.[33]

DDOE's Position

23. DDOE recommends that Residential Aid Discount[34] customers be excluded from the BSA.[35]

IV. Discussion

24. Pepco's BSA is a decoupling mechanism. Decoupling is a regulatory tool designed to separate a utility's revenue from changes in energy sales. Under traditional regulation, a utility's profitability is dependent on its sales volume. Decoupling has been offered as a solution to further public policy goals of encouraging the development of energy efficiency or to make a utility indifferent with respect to encouraging reduced energy consumption initiatives.

25. A number of states have recently considered the decoupling issue as a means of removing disincentives for utilities to invest in energy efficiency measures. The approaches vary but, in general, the mechanism insulates the utility's revenue from such factors as changes in sales volume, weather and economic activity. One of the key issues surrounding the imposition of these decoupling mechanisms is striking the appropriate balance of interests for customers, the utility and its shareholders.

26. Because the utility reaps such benefits as reduced risk, less regulatory lag, and revenue stability, it is imperative that on the other side of the ledger that the customers receive an offsetting benefit. This balancing of interests has resulted in some state public service commissions imposing reduction in the utility's ROE, imposition of certain reporting requirements, establishment of specified efficiency performance requirements and benchmarking requirements, as well as the creation of reliability standards with attendant penalties for failure to meet said standards. Consistent with the aforementioned, as this Commission undertakes the decision-making process in this

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32 WMATA (A) at 11 (Foster Direct) Phase I.

33 WGL Brief at 1.

34 The RAD Rider is a discount that is applied to and is part of Schedule R-Residential Service and Schedule AE- Residential All-Electric Service. The Rider is applied for 18 months after a customer is certified to be eligible for the Low-Income Home Energy Assistance Program (LIHEAP).

35 DDOE (A) at 2 (Lawrence Direct).

matter, it is acutely aware of the need to strike the appropriate balance in protecting the interests of consumers, the utility, and shareholders.

Return on Equity ("ROE")

27. In Phase I, each party providing testimony on this issue recommended an ROE adjustment to reflect the reduced risk associated with the implementation of the BSA. These parties agreed that there would be reduced volatility in Pepco's earnings and that the chances of the Company not earning its approved revenues would be reduced if a BSA were adopted. Pepco initially recommended an adjustment of 25 basis points to reflect the approval of the BSA adjustment, but subsequently modified its position. In particular, Pepco maintained that "[w]hile a 25 basis point adjustment would have been appropriate in the context of Phase I of this proceeding, when the Commission set rates intended to provide the Company the opportunity to earn a fair return, due to the passage of time and intervening erosion of the Company's earned return, a downward adjustment would be unjust and would send a negative signal to the financial community."[36] OPC recommended a reduction of 375 basis points, but suggested that "a compromise could be reached if the Commission is uncomfortable with such an unprecedented low cost of equity."[37] AOBA's recommendation was for a 50 basis point reduction. The basis of AOBA witness Oliver's adjustment is based on Pepco's willingness to give up its repression adjustment if the BSA is adopted, and his estimate of the dollar value of the Company's proposed repression adjustment, along with the dollar value of Pepco's 25 basis point ROE adjustment, if the BSA is approved.[38] In other words, he assumes that the benefits of the BSA are equal to or greater than the total value of the repression adjustment and the ROE adjustment.

28. Notwithstanding Pepco's position that a downward adjustment to the ROE is ill-advised at this juncture, the Commission cannot ignore the fact that, under questioning from the Commission about whether there may be more than a half notch bond rating adjustment to the cost of equity—a half notch representing something near 25 basis points—as the result of the BSA, Dr. Morin [Pepco's witness] said "I think I agree with you that a gesture like approval of the BSA would precipitate an avalanche in a sense, over the next several years of upgrades, one notch at a time, provided that the other pieces of the equation, for example, the ROE and the allowed capital structure, would be fair and reasonable as well." [39] Furthermore, the Commission is not persuaded by Pepco's contention that there should be no downward adjustment to the ROE as part of the implementation of BSA due to the erosion of its earnings in the interim. ROE is a measurement of the return received by shareholders on their investment. It is reflective of, *inter alia*, the effectiveness of management, financial decisions and economic

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36 Pepco Brief at 11.

37 OPC (B) at 48 (Rothschild Direct), Phase I.

38 AOBA (A) at 64 (Oliver Direct).

39 Tr. at 163.

conditions. A utility is allowed, but not guaranteed, the opportunity to earn the ROE authorized in a rate case proceeding. To the extent Pepco's earnings are eroded, the available course of redress is the filing of a base rate application,[40] not the denial of an offsetting benefit to consumers for the additional risks they will assume with the approval of the BSA.

29. Given the positive financial implications associated with the implementation of the BSA as discussed by Pepco Witness Morin, OPC Witness Larkin and AOBA Witness Oliver, the Commission finds that a 50 basis point adjustment to the return on equity is reasonable. A 50 basis point reduction in ROE as part of the approval of the BSA balances the ledger by providing a benefit to consumers in exchange for the benefit to the Company and shareholders of reaping lowered business risk.[41]

30. A basic tenet of utility ratemaking is that it involves a delicate balancing of investor and consumer interests.[42] The Commission is free to exercise its ratemaking function provided the rates fall within a zone of reasonableness which assures that the Commission is safeguarding the public interest – that is, the interests of both investors and consumers.[43] We therefore are of the opinion that a 50 basis point downward adjustment in the ROE is required upon implementation of the BSA. The record, as well as public policy, supports this conclusion. We find that implementation of the BSA insulates Pepco from losing revenues which, in turn, lowers the Company's business risk and results in a lower cost of capital.[44] This benefit to the Company and its shareholders requires a concomitant benefit to the ratepayers who are essentially guaranteeing that the Company will collect its revenue requirement as determined in its last base rate case. Thus, fairness to ratepayers requires that approval of a utility revenue decoupling mechanism should be accompanied by substantial utility concessions in other areas, and a downward adjustment to the ROE as part of the BSA implementation provides that concession to consumers in this case.[45]

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[40] In fact, Pepco has already availed itself of this remedy by filing an application for an increase in its retail rates and charges for electric service on May 22, 2009. *See, Formal Case 1076, In the Matter of the Application of the Potomac Electric Power Company For Authority To Increase Existing Retail Rates and Charges for Electric Distribution Service*, filed May 22, 2009 ("*F.C. 1076*")

[41] The fact that the Maryland Public Service Commission has approved a 50 basis point reduction in Pepco's ROE upon implementation of the company's BSA in that jurisdiction lends support to an ROE reduction in the matter herein. *See,* In the Matter of the Application of Potomac Electric Power Company for Authority to Revise its Rates and Charges and for Certain Rate Design Changes, Case No. 9092.

[42] *Potomac Electric Power Co. v. Public Service Commission*, 380 A.2d 126, 132 (D.C. 1977).

[43] *Office of the People's Counsel v. Public Service Commission of the District of Columbia,* 797 A.2d 719, 727 (D.C. 2002).

[44] *See F.C. No. 1053,* Order No. 14712, ¶ 351 (January 30, 2008).

[45] Tr. at 121-122.

31. Because the ROE is applied to the rate base, we determine that the ROE reduction should be allocated according to the rate base as well. Allocating the ROE adjustment based upon class rate base would match the ROE adjustment to the rate base that would have been made at the time of Order No. 14712 had the details of the BSA been determined at that time. Class rate base can be determined within the class cost of service study filed as part of the base rate case in Phase I of F.C. No. 1053. The ROE adjustment will not apply to the SL, TN, and T classes and their associated rate base since these three rate classes will not be covered by the BSA. (This issue will be discussed in more detail below.) In Order No. 14712, this Commission directed that an increased level of revenue be collected from customer and demand (non-energy) rates.[46] To preserve the effect intended, each class's ROE reduction shall be implemented by reducing only the energy (kWh) rates of the rate schedules affected.

Calculation of the BSA

32. The calculation of the BSA is set forth in Pepco's Exhibit (A)-4 and is described as follows:

$$BSA = \frac{(B \times C) - A + D}{E} = \text{monthly adjustment for the class in dollars per kWh}$$

B = average class distribution base revenue per customer for the corresponding month in the test period (as approved in Order No. 14712)
C = class customer count for the current billing month
A = actual monthly class distribution base revenue adjusted for any major service outage (excluding outages involving 10,000 or more customers for over 24 hours would increase the revenue attributable to the class)
D = cumulative true-up for over/under-collections from the class in previous months
E= class forecasted kWh sales for the second succeeding month[47]

The calculations for a given billing month will be performed in the following month (e.g. the calculations for the billing month of April will be done in May), and the BSA adjustment will then be applied to customer bills in the subsequent month (e.g. the BSA adjustment for the billing month of April will be placed on customer bills for June).[48] The adjustment is subject to a 10 percent cap. That is, any rate adjustment applied shall be limited to plus or minus 10 percent of the average test year rate per kWh for the rate class.[49]

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46 F.C. No. 1053, Order No. 14712, ¶¶ 369, 407.

47 Pepco Exhibit (A)-4.

48 Pepco (A) at 7 (Browning Supp. Direct).

49 Pepco (A) at 9-10 (Browning Supp. Direct); Pepco Exhibit (A)-4.

33. Pepco has provided sufficient information to explain the mechanics of its BSA calculation, including a historical calculation by customer class, had the BSA been approved in Order No. 14712—in response to staff DR 4-4.[50] Pepco has provided its Exhibit (A)-3 to calculate the required revenue per period information based upon weather adjusted test year parameters provided with its compliance filing for Order No. 14712. Thus, the base information for the BSA is the net result of the existing record. Pepco produces a yearly forecast of sales by month, which is approved (generally) in mid-December. The class sales values would be used for the "forward" month in the BSA process. Should that forecast be inaccurate, the BSA process reconciles each month to actual sales, thus removing concerns about inaccurate monthly class forecasting. The actual calculation of the monthly class BSA values is simple mathematics and backcasting has been provided to Staff to allow a review for accuracy.

34. The source data for the BSA calculation is the Company's billing records which are subject to Sarbanes-Oxley[51] (SOX) controls, approved test year data and the Company's budgeted forecast. These components are subject to either regulatory oversight or auditing and verification requirements and thus are reasonable components for measurement.

35. AOBA would prefer calculation of the BSA on a per customer basis. However, AOBA did not provide any information to compare the performance of the adjustment on a per customer basis to an adjustment on a per kWh basis. Without this information for consideration and review, it is difficult for the Commission to discern whether AOBA's recommendation would be the preferable methodology. Thus, the Commission declines to adopt AOBA's recommendation to calculate the BSA on a per customer basis.

36. AOBA also recommends that the BSA should be subject to an annual adjustment, or in no case be more frequent than quarterly. AOBA Witness Oliver contends that an annual adjustment would help reduce customer bills' volatility; would provide the Commission and parties with more time to review the adjustment; would be easier for customers to comprehend; and would provide an advantage of offsetting short-term variations in usage than monthly adjustments would allow.[52] An annual adjustment would result in large deferred balances subject to accrual of a return (at the overall cost of capital) on the positive or negative deferral balances.[53] The Commission believes that it is inappropriate to adopt such a potentially burdensome approach for District customers and the company and declines to adopt AOBA's annual adjustment recommendation.

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50 Commission Exhibit 2.

51 Sarbanes-Oxley Act of 2002, Pub. L. No. 107-204, 116 Stat. 745 (codified as amended in various sections of 15 U.S.C.).

52 AOBA Exhibit A at 15-18 (Oliver Direct).

53 Pepco (2A) at 18 (Browning Rebuttal).

Therefore, the Commission finds that a monthly BSA adjustment is the most reasonable and appropriate time period.

37. OPC raises concerns with regard to certain BSA inputs, in particular, the use of: (1) the weighted average of customers; (2) unbilled revenues; and (3) customer outages involving at least 10,000 customers for over 24 hours. OPC's witness Larkin recommended that the "average periodic customers" be the weighted average number of customers on the Company's system during the period associated with a calendar month.[54] Larkin contends that Pepco's method of calculating average periodic customers would distort the calculation because customers added or subtracted during the month have consumed less energy than those that have been on the system for the entire month and, therefore, less revenue is recorded for that customer. Larkin asserts that Pepco's methodology distorts the average revenue per customer both for test-year and periodic data[55] and that Pepco's method would artificially increase the number of customers reported in any given month, thereby increasing its allowed revenue under the BSA calculation.[56]

38. OPC's weighted average method is complicated and simply unnecessary. As noted by Pepco Witness Browning, it is important to ensure a match between the test-year calculation and the rate-effective period calculation. Further, Browning contends that OPC's concept does not appear in any calculation in the test year, is not currently recorded by the Company, and introduces a complicated calculation that would require additional changes to the Company's customer information system while, on the other hand, the Company's proposal to use the recorded billing month number of customers is consistent with the data for the test year and provides the proper matching between rate effective period and the test year.[57] Given the shortcomings of OPC's recommendation, the Commission declines to adopt it.

39. In contrast to Pepco's proposal to use billed revenues as an input to the calculation of the BSA, OPC recommends that the "periodic base distribution revenue" should be defined as the monthly revenue recorded by the Company for the distribution of kWhs during a specific monthly accounting period. OPC's witness Larkin submits that revenues recorded in the month associated with the bills which the Company actually rendered to customers, as well as for unbilled revenues associated with kWhs which were delivered during that month, should be considered. Larkin states that Pepco's proposal, which uses billed revenues, would create a mismatch and would most likely understate or overstate revenues during the periodic base distribution revenue period.[58] OPC reiterates

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54 OPC (A) at 12 (Larkin Supp. Direct).

55 *Id.*

56 OPC Brief at 21.

57 Pepco (2A) at 8 (Browning Rebuttal).

58 OPC (A) at 6-7 (Larkin Supp. Direct).

that unbilled revenue, which Pepco uses in its financial statements, should be included in the proposed BSA calculation so that the actual revenue earned by Pepco per customer can be estimated as accurately as possible.[59]

40. We find that Pepco's use of monthly billed revenue in the BSA calculation is not only reasonable, but also necessary because the monthly adjustments are designed to true up monthly revenue per customer to the monthly revenue per customer implicit in the revenue requirements underlying the Commission's determination of just and reasonable rates in Phase I of this proceeding. That revenue requirement, in turn, is developed from monthly test-year billed revenue, not estimated calendar month revenue. Pepco's witness Browning testified that the Company's rate case presentation is based on billed revenue, not calendar revenue.[60] In addition, OPC's unbilled revenue concept requires the estimation of class unbilled revenues that are based on overall generation values. No clear methodology has been proposed to develop the monthly class unbilled revenue estimates. The complexity of developing class unbilled revenue estimates is large and introduces a number of items that need to be resolved each month. The net effect of applying the unbilled revenue method would be of limited value in any event because unbilled revenue is first added at the beginning of the month and then subtracted at month end when it is replaced by a new estimate of unbilled revenue. We therefore reject OPC's proposal to use unbilled revenues in the BSA calculation.

41. Finally, OPC contends that the Commission, in addition to including as revenue in the BSA formula outages involving 10,000 or more customers over a 24 hour period, should require that the BSA also include as revenue all outages which exceed the total kWh which were not billed during the test-year due to outages (estimates to be made on a monthly basis). This, OPC asserts, would provide the Company with an incentive to prevent outages from exceeding the level experienced during the test year and would, in effect, maintain the same level of reliability associated with the rates authorized in the Commission's decision in Phase I of this case.[61]

42. During Phase I of this case, a concern over the BSA mechanism's ability to compensate customers during an extended outage was raised. The Commission asked whether Pepco could adjust the BSA revenues in such situations. Pepco adopted this suggestion and made provisions for it in the proposed BSA calculation by proposing a threshold outage of 10,000 customers for 24 hours before the BSA is adjusted for extended outages.[62] The 10,000 customers – 24 hour threshold is not without some basis in Commission policy. As part of the Electric Quality of Service Standards ("EQSS") promulgated by the Commission,[63] outages involving at least 10,000 customers for a 24

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59 OPC Reply Brief at 1.

60 Pepco (2A) at 2-4 (Browning Rebuttal).

61 OPC (A) at 8 (Larkin Supp. Direct).

62 Phase I Tr. at 380-381, 999-1002; Phase II Tr. at 28.

63 15 DCMR § 3600, *et. seq.*

hour duration are classified as major outages.[64] Just as the 10,000 customers – 24 hours was deemed reasonable for separating major from non-major outages in the EQSS, it is a reasonable and practical demarcation point between types of outages to be factored into the BSA formula. Calculating the revenue effects for every outage would be impractical due to the burden, time required to do so, and the insignificance (comparatively speaking) of the resulting dollar amounts.[65] The complexity and costs of calculating the revenue effects for every power outage clearly outweigh any benefit to doing so. It is also important to note here that, in any event, ratemaking is not an exact science involving precise mathematical calculations.[66] We therefore reject OPC's proposal and conclude that the "periodic base distribution revenue" should be adjusted by the amount of revenue lost due to major outages only when it involves 10,000 or more customers for 24 or more hours. In other words, if there is a major outage during the billing month, the billed revenue figure will be increased by the estimated lost revenue due to the major outage. Also, with respect to this threshold, we clarify that the outage is not deemed ended when the customer outage count falls below 10,000. The major outage ends when service has been restored to all of the customers who lost service as a result of that outage.

43. The Company has provided sufficient record evidence to support its proposed BSA calculations and the data inputs, and we are satisfied that they are not only fair and equitable, but transparent enough to verify their accuracy. The sources of the data for the BSA calculations include: (1) the Company's billing records for the billed base revenues and number of customers, which are subject to ("SOX") controls and are audited by external auditors; (2) the Commission's decision in Pepco's last base rate case for the allowed revenue per customer and the test year revenue per kWh; and (3) the Company's budget forecast.[67] We have reviewed the mechanics of Pepco's proposed BSA formula using the Company's historical calculation ("backcast") by customer class (had the BSA been approved in Order No. 14712) as a check on the accuracy of our analysis and as a template for future calculations.[68] Pepco has also provided the calculation for the required revenue per period based upon weather adjusted test year parameters submitted with its compliance filing for Order No. 14712.[69] The actual

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64 The EQSS defines a major outage as "customer interruption occurrences and durations during time periods when 10,000 or more of the electric utility's District of Columbia customers are without service and the restoration effort due to this major service outage takes more than twenty-four (24) hours." 15 DCMR § 3699.1.

65 For example, allowing the duration of service interruptions to double would result in an estimated loss of $100,000 in revenues compared to Pepco's base revenues of $250 million. Pepco (2A) at 8 (Browning Rebuttal); Tr. at 56-58 (Browning Cross).

66 *See, e.g., Public Service Commission of Oklahoma*, Cause No. PUD 200600285, Order No. 545168 (October 9, 2007).

67 Pepco (A) at 10 (Browning Supp. Direct).

68 *See* Commission Exhibit 2.

69 Pepco Exhibit (A)-3.

calculation of the monthly class BSA values is simple mathematics, straightforward and easily verifiable. We therefore approve Pepco's BSA mechanism as just and reasonable.

44. Pepco has proposed to cap the magnitude of any rate adjustments that can be applied during any period to plus or minus 10 percent of the average test year rate per kWh for the rate class.[70] No party objected to the proposed cap, and we find that capping individual adjustments at 10 percent addresses any concerns about volatility of the adjustments. We, therefore, approve the plus or minus 10 percent cap of the BSA methodology.

45. While the Commission finds the proposed methodology as well as the components of the BSA to be just and reasonable, in order to ensure that the Commission Staff and other interested parties understand the actual mechanics of the BSA calculation, the Commission hereby directs Pepco to hold a technical conference prior to the implementation of the BSA. This technical conference will facilitate the review of the application of the BSA and will be addressed more directly below.

Customer Class Application

46. The parties have expressed varying opinions with regard to the appropriate application of the BSA among the customer classes. Pepco and OPC recommended the inclusion of all customers with the exception of the SL and TN customers.[71] AOBA recommended the additional exclusion of Temporary Service customers and large commercial customers.[72] DDOE recommended that the Commission exclude the Residential Aid Discount ("RAD") customers.[73]

47. Pepco recommends that the Schedule TN customers be excluded because the schedule is intended for unmetered service where there is essentially a fixed charge (similar to a customer charge) per device, which reaches essentially the same result as the BSA, except on a per device basis rather than a per customer basis. Pepco states that the fixed usage per device is the criteria for calling the revenues stable. The Company submits that a similar situation exists in streetlights (Schedule SL), which are largely unmetered and a fixed usage ascribed to each device.[74] Both OPC and AOBA concur with Pepco's recommendation. The BSA is intended to compensate the usage reduction caused by conservation or DSM programs. In the case of SL and TN, revenues are mainly collected through a fixed charge rendering it unnecessary to impose the BSA.

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70 Pepco (A) at 9-10 (Browning Supp. Direct); Pepco Exhibit (A)-4.

71 Pepco (A) at 15 (Browning Supp. Direct); OPC Brief at 32.

72 AOBA Brief at 15-16.

73 DDOE (A) at 2 (Lawrence Direct).

74 *See*, PEPCO's response to Staff Data Request No. 5-1 included as Commission Exhibit 4.

Therefore, the Commission concurs with Pepco's, AOBA's, and OPC's recommendation to exclude the SL and TN customers from the BSA.

48. With regard to the Temporary Service and large commercial customers, AOBA argues that their inclusion is problematic. AOBA maintains that these customer classes will experience substantial rate adjustments with the imposition of the BSA. In support of its contention, AOBA points to its Exhibit 20 which indicates that, by the end of the first year of BSA implementation, the rate T class would have an accumulated deferred revenue in excess of $0.91 million of more than 50 percent of the projected $1.67 million of annualized distribution revenue for that class, despite that class being charged the maximum BSA adjustment (i.e., 10 percent of approved base revenue per customers) for 11 of the first 12 months of BSA implementation. Given such results, Rate T customers would continue to pay maximum BSA charges (i.e., 10 percent upward rate adjustments) for several years into the future even if there were no further accruals of deferred revenue in future periods. AOBA indicates that this exhibit illustrates some of the extreme impacts that Pepco's proposed BSA could have on customers within a rate class with small numbers of customers and/or large variations in usage among customers in the rate class. AOBA further contends that, given Pepco's substantial movement toward greater recovery of distribution costs from non-residential customers through customer and demand charges, the benefits of adding a BSA for those classes are substantially reduced.[75]

49. Temporary or Supplemental Service (Schedule T) is a low voltage service for construction or other commercial purposes furnished through service connection facilities of a temporary rather than a permanent nature, or for temporary electric service supplied for a limited time, such as for carnivals, festivals, etc. Such service is also available for supplementary loads that are metered and billed separately from the electricity used for lighting and other purposes in the same occupancy.[76] Pepco's rationale for inclusion of Schedule T in the BSA was the fact that "...it has a volumetric component to the rate."[77]

50. AOBA maintains that inclusion of a volumetric component in a rate schedule does not necessarily justify application of the BSA to a particular customer class since the Company recommended the exclusion of Schedule TN which also has a volumetric component.[78] AOBA further notes that for the Temporary class, there are a little over 200 customers and substantial variations in kWh use among customers within that class. Further, even without the implementation of energy efficiency programs, Rate T customers will most likely experience maximum BSA adjustments in nearly all of the

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75 AOBA Brief at 15-16.

76 *See,* Pepco, DC-T, Electricity-P.S.C. of D.C. No. 1, Fourth Revised Page No. R-7, Date of Issue: September 18, 2008; Date Effective: Service on and after October 1, 2008.

77 Tr. at 114-115.

78 AOBA Brief at 10.

first 12 months of BSA implementation. Moreover, Pepco's projections suggest that by the end of the first year of BSA implementation its deferred revenue for Rate T customers would total to more than $912,000 for a class which at the conclusion of Phase I had rates which were designed to recover only $1,350,000 of distribution revenue. According to AOBA, without any further accruals of deferred revenue after the first year of BSA implementation, it would take the Company at least 6.75 years of maximum monthly BSA adjustments to recover the projected first year revenue deferral balance.[79]

51. There are a host of unanswered questions with regard to the Schedule T customer class. Pepco cannot explain why this temporary service has many customers with long-term service usage, i.e., average number of years is 14.24 for 2007 and 15.23 for 2008.[80] Pepco Witness Browning agrees that this class requires further examination in the next rate proceeding.[81] Moreover, the evidence produced during this proceeding reveals that there are large variations in kWh usage as well as the time period in which customers remain and take service in this class. Given the extremes - some customers within the class staying less than a year and others for many years - it would prove problematic to track and make the appropriate BSA adjustments for this group of customers, i.e., equitable application of credits or surcharges. Pepco acknowledges that "[o]ne can see this class is probably not as suited to it [BSA] as some of the other classes..."[82] Notwithstanding the volumetric component included in Schedule T, the troubling revelations regarding the varying nature of usage patterns and length of service does not make this customer class suitable for the BSA at this time. Therefore, the Commission concludes that the Schedule T customers will be excluded from the BSA. The Commission directs Pepco to address inconsistencies regarding the composition of the Schedule T customer class in Formal Case No. 1076.

52. The exclusion of the RAD customers has been advocated by DDOE. Among many of DDOE's concerns is its opinion that the RAD program should be understandable to potential and existing RAD customers. DDOE also voiced concerns that low-income customers are least likely to invest in energy efficiency improvements and that RAD customers need predictability, not volatility.

53. The Council of the District of Columbia, via the Clean and Affordable Energy Act ("CAEA"),[83] established provisions for the development of low-income energy efficiency programs. The future Sustainable Energy Utility ("SEU"), when implemented, will have programs targeted to the low-income sector so that low-income customers will benefit and participate in the energy efficiency programs. Moreover, the

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79 AOBA Reply Brief at 12.

80 *See,* Commission Exhibit 5.

81 Transcript at 114.

82 Transcript at 114-115.

83 The Clean and Affordable Energy Act of 2008, D.C. Law 17-250 (October 28, 2008).

Act excuses low-income customers from certain surcharges, thereby lessening their financial burden as it pertains to the implementation of the CAEA.[84] Since low-income customers will be active participants in newly created energy efficiency programs pursuant to the CAEA and will receive certain financial relief under the Act, the Commission believes that it is appropriate to include RAD customers in the BSA.

54. Further, with regard to DDOE's concerns for bill stability for RAD customers, it is a desirable goal, but simply excluding RAD customers will not achieve that goal since the price volatility associated with energy, i.e., SOS, will remain. By contrast, the BSA will be subject to a 10 percent cap which will aid in stabilizing the distribution portion of customers' bills.

55. To the extent the concept of the BSA is "difficult to understand", this concern is not limited to RAD customers. As part of the approval of the BSA mechanism, Pepco will be required to design outreach materials and bill inserts that adequately explain the BSA construct for all customers, not simply RAD customers. This issue will be discussed below.

56. Some areas of concern raised by DDOE are either addressed in the CAEA or through the structure of the BSA and Commission directive; thus the Commission rejects DDOE's recommendation to exclude RAD customers from the BSA.

Implementation and Reporting Requirements

57. To ensure that the Commission and interested parties will be able to assess the success of the BSA; verify the accuracy of the adjustments; and ensure that certain standards are still being met in the light of the BSA's implementation, the Commission directs Pepco to comply with certain implementation and reporting requirements.

58. Pepco proposes to file with the Commission the information contained in Exhibit (A)-4 for each class of customer each month. This information will provide the necessary data to enable interested parties to compute the BSA. In addition, the Company will provide the workpapers supporting any estimated lost revenues caused by major outages as part of its submissions. These lost revenue estimates, supporting workpapers, and the incorporation of these figures into the BSA calculations will be made as soon as possible after the storm event. These calculations will be subject to SOX compliance which will permit an additional layer of comfort that the data is accurate and verifiable.

59. In addition to the above, the Commission requires Pepco to provide the following information on an annual basis to evaluate the efficacy of the BSA:

1. ***Revenue Comparison Report*** - (a) Provide a comparison of revenues that would have been collected under traditional regulation to those actually collected under the BSA; and (b) provide data setting forth the relative effects

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84 *Id.* at § 210(b) (4) (2008).

of the energy efficiency programs, actual weather, and other factors on revenue.

2. ***Bill Comparison*** – Provide a comparison of average bills to those under traditional regulation.

60. As previously noted, in an ideal situation a decoupling mechanism should be accompanied by the implementation of energy efficiency measures and service quality standards. However, given the procedural posture of several docketed matters pending before the Commission this cannot occur. To allay any concerns of the parties regarding these issues and their implication regarding the BSA, the Commission advises the parties that these issues will be addressed in the docketed matters currently underway.

61. Additionally, the Commission directs Pepco to prepare appropriate bill inserts to explain the operation and effect of the BSA on customers and to minimize customer confusion regarding the implementation of the BSA. Pepco shall also post an explanation of the BSA on its website. The bill inserts and the website posting will be subject to prior Commission review and approval.

62. As part of the implementation process, the Commission also directs Pepco to hold a technical conference as set forth in Attachment A wherein all interested parties will be able to view the calculation of the inputs, the actual calculation of the BSA, and the application of the BSA.

V. Conclusion

63. Based on the evidence presented, the Commission concludes that the BSA methodology and the components thereof are just and reasonable. Further, we conclude that a 50 basis point reduction of Pepco's Return on Equity ("ROE") is reasonable and appropriate upon implementation of the BSA, and is consistent with the balancing of interests of customers, the utility, and shareholders. The reduction in the ROE shall be applied to BSA customers as designated in this order. The BSA shall be applied to all customer classes except SL, TN, and T. Pepco is directed to address the concerns raised during the course of this proceeding pertaining to the T class in Formal Case 1076. Also, Pepco is directed to educate customers regarding the implementation of the BSA by bill inserts and the posting of an explanation of the BSA on Pepco's website. The inserts and website posting will be subject to prior Commission review and approval. Pepco shall also comply with the reporting requirements set forth in this Order. In addition to the monthly reviews of the calculation of the BSA, the BSA shall be subject to an annual Commission review. Finally, Pepco is hereby directed to file its compliance filing with the Commission within 10 days of this Order and shall schedule and hold a technical conference for the Commission Staff and interested parties to facilitate the parties' understanding of the first month adjustment. The BSA shall commence on November 1, 2009, and will be effective prospectively in the manner set forth herein and in accordance with the Implementation Schedule as set forth in Attachment A.

THEREFORE, IT IS ORDERED THAT:

64. Pepco's proposed BSA is **GRANTED** in accordance with the discussion herein and the directives set forth in Attachment A;

65. Pepco shall adjust its return on equity by 50 basis points upon implementation of the BSA.

66. Pepco shall submit to the Commission on an annual basis a Revenue Comparison Report and a Bill Comparison, as described herein;

67. Pepco is authorized to commence the BSA on November 1, 2009;

68. Pepco is directed to file its compliance filing with the Commission within 10 days of the date of this Order;

69. Pepco is directed to schedule and hold a technical conference for Commission Staff and interested parties to facilitate the parties' understanding of the BSA process and the first month's adjustment.

70. OPC's Motion for Leave to Comment and Comments to the Response of Pepco to Commission Data Request, filed on July 29, 2009, is **DENIED**.

A TRUE COPY: **BY DIRECTION OF THE COMMISSION:**

CHIEF CLERK: **DOROTHY WIDEMAN**
COMMISSION SECRETARY

Attachment A

BSA Implementation Schedule

1. Pepco shall file a compliance filing with the Commission within 10 days from the date of this Order. The compliance filing shall include the new rates for the classes covered by the BSA based on the ROE reduction ordered herein and the BSA calculations, as approved in this Order, for the months of August and September 2009. Comments from the parties, if any, shall be filed within 10 days from the date of the compliance filing. Unless ordered otherwise, the new rates will go into effect concurrently with the commencement of the BSA on November 1, 2009.

2. Application of the BSA shall commence on November 1, 2009, and will be effective prospectively from that date.

3. As part of the implementation process, Pepco shall prepare appropriate bill inserts to explain the operation and effect of the BSA on customers and to minimize customer confusion regarding the implementation of the BSA. Pepco shall also post an explanation of the BSA on its website. The bill inserts and the website posting are subject to prior Commission review and approval.

4. On or before December 1, 2009, Pepco shall conduct a technical conference wherein all interested parties will be able to view the calculation of the inputs, the actual calculation of the BSA, and the application of the BSA. The matters to be discussed during the conference shall include: (1) review of Pepco's BSA inputs extraction process; (2) review of SOX for the BSA process; (3) Pepco's external auditor review; (4) review of the compliance filing; and (5) final reporting requirements. Additionally, Pepco shall demonstrate how information extracted from its billing system for the months of August and September 2009 is transferred to the BSA monthly filing spreadsheet(s) as detailed in Paragraphs 6 and 7 below.

5. The initial BSA filing shall be made on or before December 10, 2009 for adjustments resulting from the November bills. The parties shall file comments on the initial filing within seven (7) days from the date Pepco makes its filing. The Commission will issue an Order concerning compliance within 10 days from the date Pepco makes its filing. The BSA adjustment shall appear on customer bills beginning with the January 1, 2010 billing cycle.

6. For the initial BSA filing, Pepco shall file the following information with the Commission and serve copies of same on the parties:

(1) A narrative description of the BSA calculation;

(2) A summary of the BSA adjustment for each customer class;

(3) The BSA calculation using Pepco Exhibit (A)-4 as a template for each customer class, the calculation to include a line to record:

(a) The cumulative total of the BSA adjustment for each customer class for the current calendar year;

(b) The cumulative total of the BSA adjustment for all customer classes for the current calendar year;

(c) The cumulative BSA adjustment for an average bill for the current calendar year;

(d) The cumulative total of the BSA adjustment for each customer class;

(e) The cumulative total of the BSA adjustment for all customer classes; and

(f) The cumulative BSA adjustment for an average bill; and

(4) Workpapers to support calculations and inputs, to include Excel files (with all inputs, formulas, and macros intact).

7. In subsequent BSA monthly filings, Pepco shall file with the Commission:

(1) A summary of the BSA adjustment for each customer class;

(2) The BSA calculation using Pepco Exhibit (A)-4 as a template for each customer class (including the cumulative information as described above); and

(3) Workpapers to support the calculations and inputs, to include Excel files (with all inputs, formulas, and macros intact).

8. All subsequent monthly BSA filings shall be made on or before the 10th day of each month and shall be reviewed by the Commission without the filing of comments by parties and without issuance of an Order of approval. All subsequent monthly BSA filings shall be deemed approved and shall become effective for the next month in the absence of a Commission Order directing otherwise.