

**BEFORE THE
TENNESSEE REGULATORY AUTHORITY
AT NASHVILLE, TENNESSEE**

IN RE:

**DOCKET TO EVALUATE CHATTANOOGA GAS COMPANY'S GAS PURCHASES
AND RELATED SHARING INCENTIVES**

DOCKET NO. 07-00224

**DIRECT TESTIMONY
OF
TERRY BUCKNER**

May 30, 2008

1 **Q. Please state your name for the record.**

2 A. My name is Terry Buckner.

3

4 **Q. By whom are you employed and what is your position?**

5 A. I am employed by the Consumer Advocate and Protec-
6 tion Division ("CAPD") in the Office of the Attorney General
7 for the state of Tennessee ("Office") as a Regulatory Analyst.

8

9 **Q. How long have you been employed in conjunction with the**
10 **public utility industry?**

11 A. I have been employed in conjunction with the public
12 utility industry for approximately thirty years. Before my
13 current employment with the Office, I was employed by the
14 Comptroller's Office for the state of Tennessee for nearly two
15 years as the Assistant Director responsible for public utility
16 audits after approximately eight years of prior employment
17 with the Office. Formerly, I was employed with the Tennessee
18 Public Service Commission ("Commission") in the Utility Rates
19 Division as a financial analyst for approximately six years. My
20 responsibilities included testifying before the Commission as to
21 the appropriate cost of service for public utilities operating in

1 Tennessee. Prior to my employment with the Commission, I
2 was employed by TDS Telecom for eight years and the First
3 Utility District of Knox County for three years.

4
5 **Q. What is your educational background and what degrees do**
6 **you hold?**

7 A. I have a Bachelors degree in Business Administration
8 from the University of Tennessee, Knoxville with a major in
9 Accounting. I am also a Tennessee Certified Public Accountant
10 and a member of the American Institute of Certified Public
11 Accountants.

12
13 **Q. Would you briefly describe your responsibilities as a**
14 **Regulatory Analyst with the CAPD?**

15 A. I prepare testimony and financial exhibits in rate
16 proceedings as an employee with the CAPD. Additionally, I
17 review tariff filings by the Tennessee Regulatory Authority
18 ("TRA") certificated utilities operating in Tennessee.

1 **Q. What is the purpose of your testimony?**

2 A. The purpose of my testimony is to address issues 1, 2,
3 and 10 through 14 from the issues list in this docket before the
4 TRA regarding just and reasonable compensation to the
5 ratepayers for the sale, lease, release or assignment of gas
6 supply and storage assets (also known as "system capacity") by
7 Chattanooga Gas Company ("CGC") through its affiliated asset
8 manager Sequent Energy Management, LP ("Sequent").
9

10 **Q. Please describe the relationship between CGC and Sequent**
11 **in the provision of natural gas for the ratepayers of**
12 **Tennessee.**

13 A. AGL Resources Inc. is the parent company of both CGC
14 and Sequent. Sequent is an asset manager for CGC. CGC has
15 contracts with Sequent to purchase natural gas and contracts
16 with the pipeline companies to transport and to store natural
17 gas.
18
19
20
21
22

1 **Q. What activities are performed by CGC and Sequent in the**
2 **provision of natural gas service for the ratepayers of**
3 **Tennessee?**

4 A. There are four primary activities necessary for the
5 provision of natural gas in which CGC and Sequent are
6 employed: (1) distribution; (2) storage; (3) transport; and (4)
7 marketing. As previously mentioned, CGC has contracts with
8 the pipeline companies for transportation and storage. These
9 contractual assets along with CGC's physical assets are
10 managed by Sequent to meet the firm full gas supply
11 requirements of CGC. CGC is a local distribution company
12 ("LDC"), which is the final activity in delivering natural gas to
13 the ratepayers.

14
15 **Q. Please describe the distribution activity of CGC in**
16 **Tennessee.**

17 A. CGC is an investor owned LDC, which takes ownership
18 of the natural gas and delivers it to each individual ratepayer's
19 location of use. CGC has exclusive rights to distribute natural
20 gas to their certificated service areas in Bradley and Hamilton
21 counties in Tennessee. Therefore, CGC is a natural monopoly

1 subject to the regulation of the TRA. CGC delivers the natural
2 gas to their service areas through points known as, "citygates."
3 Once the natural gas passes the citygate it is ordinarily
4 delivered or distributed to each individual ratepayer's location
5 of use by CGC. CGC's affiliate transaction guidelines prohibit
6 Sequent from making sales "to any customer's premise that is
7 connected to the Company's distribution facilities."¹
8

9 **Q. Please describe the storage, transportation, and marketing**
10 **activities of CGC and Sequent in Tennessee.**

11 A. Stored natural gas is primarily insurance to meet the
12 increased demand for the winter months. Stored natural gas
13 can also be used to maintain reliable service during natural
14 disasters or unforeseen accidents. Natural gas can be stored
15 with the interstate pipeline companies and at CGC's liquified
16 natural gas ("LNG") facility. Formerly, the pipeline storage
17 activity was part of the bundled natural gas commodity costs
18 sold by the pipelines to the LDCs. However, the Federal
19 Energy Regulatory Commission's ("FERC") Order 636
20 ("Order") in 1992 changed the usage of stored gas. The Order

¹CGC Response to CAPD Data Request #38 Attachment A, Standards of Conduct, Item #5.

1 effectively deregulated the stored gas, which was previously
2 available only to the pipelines in meeting the demand of the
3 LDCs. As a consequence, stored gas is now used for
4 commercial profit making and operational requirements.
5 Natural gas industry participants, e.g. Sequent, can now store
6 gas when commodity gas costs are low, but also withdrawing
7 and selling the stored gas when prices are high.

8 Also, CGC's contracts for transportation capacity and
9 storage capacity usually exceed their actual annual demand
10 requirements. The excess capacity results in what is known as
11 demand charge or capacity charge because the ratepayer's bill
12 includes not only what was used, but also includes what the
13 ratepayer expects to have available on a peak day of natural
14 gas usage. So, the ratepayer pays for the annual excess
15 capacity in full to meet the peak day demand for one day in a
16 year. As a result, Sequent uses the excess capacity and captures
17 incremental operating margin in the natural gas market and
18 shares the margin with CGC's ratepayers.

1 **Q. What is Sequent earning?**

2 A. AGL Resources wholesale services segment consists
3 primarily of Sequent and focuses on asset management,
4 transportation, storage, produce and peaking services and
5 wholesale marketing. AGL Resources' December 31, 2007 10-K
6 to the Securities and Exchange Commission ("SEC") reported
7 consolidated earnings before income taxes ("EBIT") of \$463
8 million and the wholesale services ("Sequent") contributed \$34
9 million in EBIT.² The \$34 million in EBIT was 41% of the \$83
10 million in operating revenues. However, Sequent contributed
11 \$90 million in EBIT in 2006 to AGL Resources' nearly identical
12 EBIT of \$464 million. The \$90 million in EBIT was nearly 50%
13 of their \$182 million in operating revenues. Comparatively, the
14 distribution services segment's EBIT percent of operating
15 revenues was only 20% in 2007 and 19% in 2006.
16 Consequently, Sequent provides a significant and a highly
17 sensitive financial contribution to AGL Resources. AGL
18 Resources believes that "EBIT is a useful measurement of our
19 performance because it provides information that can be used
20 to evaluate the effectiveness of our businesses from an

²AGL Resources Inc. 2007 10-K, Pages 86-87.

1 operation perspective, exclusive of the costs to finance those
2 activities and exclusive of income taxes, neither of which is
3 directly relevant to the efficiency of those operations.”³ No
4 other internal or external financial statements were provided to
5 the CAPD by CGC regarding the earnings of Sequent.
6

7 **Q. What is the current compensation between CGC and**
8 **Sequent?**

9 A. CGC and Sequent entered a contract known as the “Asset
10 Management and Agency Agreement” (“Agreement”) on April
11 1, 2008. The Agreement was approved by the TRA in Docket
12 #08-00012. The Agreement has a three year term ending on
13 March 31, 2011.⁴ In the Agreement, Sequent pays CGC 50% of
14 the net margin and provides an Annual Guaranteed Minimum
15 amount for each of the three twelve month periods ended
16 March 31.⁵ The Annual Guaranteed Minimum amount has
17 been deemed confidential by CGC in this docket. The
18 Agreement improves the compensation prospectively for the

³AGL Resources Inc. 200710-K, Page 86.

⁴Asset Management and Agency Agreement, Section 11, Page 9.

⁵Asset Management and Agency Agreement, Section 4, Pages 6-7.

1 ratepayers of CGC and is due in part to the scrutiny brought by
2 the TRA in this proceeding.

3
4 **Q. How does CGC's ratepayer compensation compare to the**
5 **ratepayer compensation provided by the other AGL**
6 **Resources' LDCs asset management agreements?**

7 A. AGL Resources identifies five other LDCs in their annual
8 10K report to the SEC.⁶ The five other LDCs are Elkton Gas,
9 Elizabethtown Gas, Florida City Gas, Virginia Natural Gas, and
10 Atlanta Gas Light. According to the 10-K and company
11 responses, the Elkton Gas compensation is a fixed fee of
12 approximately \$11,000; the Elizabethtown Gas compensation is
13 a fixed minimum fee plus different sharing tiers above the
14 minimum fee; the Atlanta Gas Light compensation has varying
15 annual minimum fees plus a fixed sharing percentage; the
16 Virginia Gas compensation has a fixed minimum fee plus
17 different sharing tiers above the minimum fee; and the Florida
18 City compensation is a profit sharing mechanism. The
19 contracts between Sequent and the five LDCs are deemed
20 confidential by CGC in this proceeding.

⁶AGL Resources Inc. 200710-K, Page 11.

1 Therefore, based upon what is known from the other
2 LDC contracts and historical compensation, the Agreement
3 provides prospective compensation to CGC, which is
4 comparable to its sister LDCs.

5
6 **Q. How does CGC's ratepayer compensation compare to the**
7 **ratepayer compensation provided by the other Tennessee**
8 **LDC's asset management agreements?**

9 A. There are three regulated major LDCs in Tennessee with
10 asset management agreements providing compensation to
11 ratepayers: CGC; Atmos Energy Corporation ("AEC"); and
12 Piedmont Natural Gas ("PNG"). Over the last three plan years,
13 CGC has compensated its ratepayers nearly \$8 million; PNG
14 has compensated its ratepayers approximately \$10.8 million;
15 and AEC has compensated its ratepayers only \$1 million.⁷
16 PNG does not have an affiliated asset management contract,
17 but as a result of a competitive bidding process provides 75%
18 of a fixed annual payment to its ratepayers. The non-affiliated
19 asset manager retains 100% of the net margin. Again, CGC's
20 Agreement compensation is favorably comparable to the

⁷The amount is exclusive of the compensation provided to ratepayers through their PBR as noted in TRA Docket #05-00253.

1 provided compensation of the two other regulated major LDCs
2 in Tennessee.

3
4 **Q. How does CGC's ratepayer compensation compare to the**
5 **ratepayer compensation provided nationally by other LDCs?**

6 A. When compared to ratepayer compensation in state
7 jurisdictions other than AGL, the ratepayer compensation is too
8 low.

9
10 **Q. Do you know of any examples of asset management**
11 **arrangements in which consumers are allowed to retain more**
12 **than half of the benefits?**

13 A. Yes. The Indiana Utility Regulatory Commission, in
14 Cause No. 42973, approved an asset management arrangement
15 in which consumers receive the bulk of the benefits. Part 3-e of
16 the order, starting on page 7, discusses the "Profit Sharing."
17 The order divides the capacity assets into two equal parts that
18 are treated differently in the method of deriving benefits from
19 them. One half of the capacity is devoted to "a pre-arranged
20 sales process that will solicit bids." Consumers receive 85% of
21 the value derived from that process. The other half of the

1 capacity is retained by the utility, and the utility markets that
2 half of the capacity itself. Consumers receive 75% of the value
3 derived from that process. Obviously, there are differences
4 between this example and the asset management contract at
5 issue in the present docket, but the point is that it is possible
6 and practical for a state regulatory authority to establish a
7 system of marketing capacity assets that is designed primarily
8 to benefit the consumers who have paid 100% of the costs for
9 those assets.

10
11 **Q. Are there any difficulties in obtaining or discussing**
12 **additional examples of asset management arrangements that**
13 **are designed primarily for the benefit of consumers?**

14 **A.** Yes. Claims of confidentiality, whether or not they are
15 legitimate, impede the CAPD's ability to obtain or discuss
16 examples of asset management arrangements. Every example
17 of an asset management arrangement that CGC supplied to the
18 CAPD in discovery is designated as confidential by CGC. To
19 the extent that LDCs and asset managers attempt to keep their
20 arrangements secret, the CAPD's ability to obtain or discuss
21 examples for the TRA is limited. It is limited in that the CAPD

1 cannot discuss in an open proceeding before the TRA other
2 AGL's asset management agreements with CGC's sister LDCs.
3 Also, it is limited in having access to Sequent's asset
4 management agreements with other utilities for comparison
5 purposes.⁸
6

7 **Q. Is the asset management arrangement from the Indiana**
8 **Utility Regulatory Commission, Cause No. 42973, designated**
9 **as confidential?**

10 A. No. The order, the agreement, and the attachments are
11 posted on the web site of the Indiana Utility Regulatory
12 Commission.
13

14 **Q. Please address issue #1 of the Issues List in this docket,**
15 **which is, "Should the current CGC sharing mechanism for**
16 **profits from the sale, lease, or release of capacity and any**
17 **other gas supply assets, be revised? If so, how?"**

18 A. Yes. The sharing allocation between CGC and the asset
19 manager should be changed from 50%/50% to 85% for CGC
20 and 15% for the asset manager. The sharing between

⁸TRA Order dated April 29, 2008, Denial of CAPD Discovery Request #34.

1 consumers and CGC should be changed from 50%/50% to 90%
2 for consumers and 10% for CGC. The resulting allocation
3 would be 76.5% for consumers, 15% for the asset manager, and
4 8.5% for CGC.

5
6 **Q. Do you have any basis for changing the sharing from the**
7 **current allocation of 50%/50% between CGC and the asset**
8 **manager?**

9 A. Yes. There is not a standard arrangement between LDCs
10 and their asset managers. The arrangements vary, and
11 allocations are made in different ways. Allocating sharing
12 percentages 50%/50% between CGC and the asset manager is
13 not essential. The TRA can and should consider other
14 arrangements.

15 For example, attached is an exhibit of where other state
16 jurisdictions have ordered substantially more in compensation
17 to the rate payers.⁹

⁹Cause No. 42973, Indiana Utility Regulatory Commission, Page 7; 2005 WL 2860324 (Ind. U.R.C.), Pages 14 and 27; 2007 WL 2331025 (Del. P.S.C.), Page 8; 2006 WL 146068 (N.Y.D.P.S.), Page 8; 2005 WL 140073 (Ohio P.U.C.), Pages 13, 20; 2005 WL 1607153 (CT. D.P.U.C.), Page 4; 237 P.U.R. 4th 474, 2004 WL 3050776 (Mass. D.T.E.), Pages 1 and 19; 94 MD. P.S.C. 262, 2003 WL 23573860 (MD P.S.C.), Pages 3 and 5; 94 MD P.S.C. 409, 2003 WL 23574233 (MD P.S.C.), Page 1; 2002 WL 31958785 (PA P.U.C.), Page 2; 208 P.U.R. 4th 97, 2001 WL 490516 (NY P.S.C.), Pages 11 and 42; and 215 P.U.R. 4th 185, 2002 WL 554356 (CT. P.U.C.) Pages 178, 179, 198.

1 **Q. Do you know how the 50%/50% sharing between CGC and**
2 **the asset manager originated?**

3 A. The discovery responses indicate that the sharing
4 originated from negotiations between CGC and Sequent.¹⁰ The
5 previous asset management arrangement was not put out for
6 bid. The new asset management arrangement that is now in
7 effect was put out for bid, but the 50%/50% sharing was fixed
8 within the bidding process. The bids were based on the annual
9 guaranteed minimum. The 50%/50% sharing, which was fixed
10 in the bidding process, appears to be simply a legacy of the
11 negotiated arrangement between CGC and its affiliate, Sequent.

12
13 **Q. If the sharing between CGC and the asset manager is**
14 **changed to 85% for CGC and 15% for the asset manager,**
15 **would you expect that the potential asset managers would**
16 **bid smaller amounts for the annual guaranteed minimum**
17 **than they would under 50%/50% sharing?**

18 A. Most likely, yes.
19
20

¹⁰CGC Discovery Response to CAPD #36.

1 Q. Why would you be willing to accept smaller annual
2 guaranteed minimum payments for consumers?

3 A. Obviously, there is a trade off, but consumers could be
4 better off over the long term with a higher guaranteed
5 percentage of the sharing rather than with a higher annual
6 guaranteed minimum payment.

7 First of all, the annual guaranteed minimum has been
8 designated confidential. Therefore, consumers do not know
9 and cannot know what the annual guaranteed minimum
10 payment is. On the other hand, the sharing percentage is not
11 confidential. Consequently, consumers can have greater
12 confidence that they are receiving value for the assets for which
13 they have paid 100% of the cost.

14 Secondly, there is a risk that the current annual
15 guaranteed minimum will remain fixed for a period of seven
16 years. The current asset management contract has a term of
17 three years and the possibility of a four-year extension for a
18 total of seven years. After seven years the annual guaranteed
19 minimum could be stale. Considering seven years of inflation,
20 the annual guaranteed minimum in seven years will be worth
21 less than the annual guaranteed minimum today.

1 Finally, the industry has changed over time, and it is
2 likely that the industry will continue to change over time in the
3 future. If the profits from the assets increase over time,
4 consumers will benefit from a higher percentage of the sharing.
5 However, if the profits from the assets increase over time, then
6 consumers would not benefit as much with a fixed annual
7 guaranteed minimum in the long term.

8
9 **Q. Why do you recommend that CGC split the money that it**
10 **receives from the asset manager with consumers on the basis**
11 **of 90% for consumers and 10% for CGC?**

12 **A.** CGC apparently has the right to keep 50% of the money
13 that it receives from the asset manager based on its
14 Interruptible Margin Credit Rider ("IMCR"). That would leave
15 consumers with only 25% of the money. Yet, CGC presently
16 allows the full amount that it receives from the asset manager
17 to benefit consumers, and CGC should be commended for its
18 willingness to do that. However, there is no guarantee that
19 CGC will continue this practice indefinitely, especially if a non-
20 affiliate ever wins the bidding for a future asset management
21 contract.

1 Therefore, the TRA should change the language of the
2 IMCR to insure that the customers get at least 50% of the
3 compensation between consumers and CGC in the future.

4 Currently, AEC shares the money it gets from its asset
5 manager 90% for consumers and 10% for AEC. The
6 recommended sharing percentages for CGC are the same as
7 AEC. Consumers would get 90% of 85% for a total of 76.5% of
8 the sharing. By making the recommended changes, the TRA
9 would make it possible for a non-affiliate to win the bidding for
10 future asset management contracts. Under the current sharing
11 arrangement consumers are at risk of being reduced to 50% of
12 50% for a total of only 25% of the sharing, especially if a non-
13 affiliate wins the bidding for a future asset management
14 contract.

15
16 **Q. Do you have an opinion about whether 25% sharing for**
17 **consumers would be fair and reasonable?**

18 **A.** Yes. It would not be fair or reasonable for consumers to
19 be reduced to only 25% sharing. As previously stated.
20 consumers pay for 100% of the costs of the assets at issue
21 through the Purchased Gas Adjustment ("PGA"). It would be

1 unfair and unreasonable to reduce the share that consumers
2 receive to 25% of the profits derived from these assets. In order
3 to protect consumers in the future and in order to give non-
4 affiliates a more level playing field on which to compete with
5 Sequent in the future, the TRA should reform the sharing
6 arrangement. Potential non-affiliate asset managers could bid
7 on future asset management contracts without the risk that
8 consumers would be reduced to a mere 25% of the sharing,
9 which would be unjust and unreasonable.

10
11 **Q. What is the basis for your concern that CGC would reduce**
12 **the consumers' share to a total of 25% in the event that a non-**
13 **affiliate wins the bidding for a future asset management**
14 **contract?**

15 A. In TRA Dockets #04-00402 and #04-00403, the Order
16 Adopting Tariff Revisions, December 5, 2006, on page 2 says,
17 "Audit staff notes that CGC would likely opt to retain 50% of
18 asset management fees if an agreement is signed with a third
19 party[.]" Reducing consumers' share by 50% means that
20 consumers would receive only half of 50%, which is 25%.

1 Q. What do you recommend to the TRA in terms of timing for
2 the changes that you have proposed to the sharing
3 arrangement?

4 A. The TRA could implement the proposed changes to the
5 sharing arrangement at the end of the expiration of the initial
6 three-year term of the current asset management contract.
7 Ideally, the arrangement would be changed immediately
8 through new bids. However, the asset manager bid on the
9 annual guaranteed minimum on the basis of a deal that it
10 reasonably anticipated would last three years. If the asset
11 manager had known that the deal would last less than three
12 years, it might have bid less for the annual guaranteed
13 minimum.

14
15 Q. Should the TRA wait for the expiration of the seven-year
16 extended contract?

17 A. No. The asset manager entered into the contract with full
18 knowledge that the contract might not be extended for a period
19 of seven years. To whatever extent the asset manager expected
20 the deal to last seven years, such expectation was and is
21 unreasonable. Seven years is a very long time in the context of

1 this industry, and it would be unfair to consumers to make
2 them wait that long for reform of the system. Again, by the
3 seventh year the annual guaranteed minimum might be stale.
4 By the seventh year, CGC might decide to opt to reduce
5 consumers' share of the profits to 25%, which it currently
6 appears to have the option to do. A lot can happen in seven
7 years, and seven years is too long to wait. To wait for the
8 expiration of the extended seven-year term would disregard
9 the legitimate interests of consumers.

10
11 **Q. Please address issue #2 of the Issues List in this docket,**
12 **which is, "Is the current bidding process fair and**
13 **reasonable?"**

14 **A.** No, not entirely. The inclusion of affiliate guidelines with
15 standards of conduct and RFP procedures in CGC's tariff is
16 commendable. While the RFP procedures for selection of an
17 asset manager and/or gas provider allow for the receipt of
18 competitive bids, the criteria for choosing the winning bid
19 proposal is ambiguous. The RFP procedures do offer some
20 minimum criteria for evaluation purposes, but "The winning
21 bid proposal shall be the one with the best combination of

1 attributes based on the evaluation criteria.” Further, “The
2 Company shall maintain records demonstrating its compliance
3 with the evaluation and selection procedures.”¹¹ Yet, when
4 asked to explain how the historic sharing formula and
5 percentages were determined for the asset management
6 contracts between CGC and Sequent, CGC simply stated, “The
7 sharing provisions....were negotiated by the parties.”¹²

8 Until the evaluation criteria becomes more transparent
9 and objective, then the possibility of an unaffiliated asset
10 manager remains unlikely.

11
12 **Q. Do you recommend any other changes that the TRA should**
13 **make to the contract that is put out for bid when the current**
14 **three-year contract approaches expiration?**

15 **A.** Yes. The CAPD argued for specific changes to the
16 contract in TRA Docket #08-00012. There was some concern
17 expressed at the hearing on those issues that the bidders relied
18 on the form contract in making their bids. If the TRA orders
19 the changes prior to the RFP going out, that concern would not

¹¹CGC Response to CAPD Data Request #38 Attachment A, RFP Procedures, Item #4.

¹²CGC Response to CAPD Data Requests #36.

1 exist the next time bidders analyze the contract. The CAPD's
2 arguments on those issues are included in its brief and reply
3 brief in TRA Docket #08-00012.

4
5 **Q. Please address issue #10 of the Issues List in this docket,**
6 **which is, "Is the amount paid by Sequent for the right to**
7 **utilize or market assets, which are paid for by the customers**
8 **of CGC, representative of the fair market value of such**
9 **assets?"**

10 **A.** Before this question can be addressed, it must be
11 understood that there is a distinction between what an asset
12 manager is willing to pay for the right to the assets and the
13 profitability of the assets. The profitability of the assets is as
14 fluid as the natural gas market. The asset manager, Sequent in
15 this docket, desires to minimize the cost of obtaining the right
16 to manage the assets, while at the same time desires to
17 maximize its profit. Sequent has agreed to an Annual
18 Guaranteed Minimum payment and a maximum of 50% of the
19 Net Margin be paid to CGC.

20 Therefore, the amount paid by Sequent for the right to
21 utilize or market assets is not representative of the fair market

1 value of such assets.

2
3 **Q. Please address issue #11 of the Issues List in this docket,**
4 **which is, "Is it proper to impute to CGC all or a portion of the**
5 **profits Sequent generates through its management of CGC's**
6 **idle gas supply assets and excess capacity?"**

7 A. Yes, clearly the ratepayers have paid for the excess
8 capacity, which Sequent intends for profit-making. The issue is
9 not the propriety of the imputation, but the amount of
10 imputation. A 50/50 sharing imputation is a minimum
11 threshold for the ratepayer. Yet, there is a need to fairly
12 balance what the ratepayers have paid for and what profit
13 Sequent can generate through its expertise of asset
14 optimization.

1 Q. Please address issue #12 of the Issues List in this docket,
2 which is, "What regulatory approval should occur in the
3 event that assets are added or removed from the asset mix set
4 forth in the asset management agreement? What affiliate
5 guidelines should be in place if those removed assets are
6 subsequently purchased by an affiliate or parent company?"

7 A. As to the first question of the issue, the agreement states,
8 "If any new Assets are included in this Agreement, the parties
9 will re-evaluate the Annual Guaranteed Minimum as set forth
10 in this Agreement."¹³ Given this language, it is possible the
11 ratepayers would be subject to additional demand charges for
12 additional capacity, which could be used for additional
13 optimization by Sequent. However, it is unclear exactly how
14 the re-evaluation of the Annual Guaranteed Minimum would
15 be of benefit to the ratepayers or even be subject to TRA
16 approval. Certainly, the TRA should diligently evaluate and
17 approve the annual supply plan of CGC within the context of
18 the agreement to avoid excessive demand charges to the
19 ratepayers.

20 As to the second question, CGC's affiliated transaction

¹³Asset Management and Agency Agreement, Section 6, Page 7.

1 guidelines state, "The Company shall maintain sufficiently
2 detailed records of all gas transactions with any affiliated gas
3 supplier."¹⁴ It could be understood that "all gas transactions"
4 means purchases and sells. However, there is no audit
5 mechanism in place to verify the accuracy of the detailed
6 records and to verify that the transactions are in the public
7 interest.

8 Therefore, while it appears to be an adequate guideline
9 for the matter in question, there remains a need for an
10 independent assessment of the transactions for compliance to
11 the guideline. This can be accomplished through a triennial
12 audit to address the gas supply plan, compensation, and verify
13 transactions.

14
15 **Q. Please address issue #13 of the Issues List in this docket,**
16 **which is, "Are the current affiliate guidelines sufficient? If**
17 **no, in what ways(s) should they be amended?"**

18 **A.** No. CGC could reduce the consumers' share from a total
19 of 50% to a total of only 25%, if a non-affiliate wins the bidding
20 on a future asset management contract. The TRA should

¹⁴CGC Response to CAPD Data Request #38 Attachment A, Standards of Conduct, Item #9.

1 prohibit CGC from harming the interests of consumers in this
2 way, by prohibiting more of a share from consumers based on a
3 potential non-affiliate status of the asset manager.

4 In the future, the TRA should formalize the sharing of
5 CGC's 85% share of the profits at 90% for consumers and 10%
6 for CGC. Additional concerns are addressed by Dr. Brown in
7 his testimony.

8
9 **Q. Please address issue #14 of the Issues List in this docket,**
10 **which is, "If the CGC were to engage in asset management**
11 **itself, how should the Tennessee Regulatory Authority**
12 **monitor CGC's asset management activities?"**

13 **A.** CGC is a rate of return regulated public utility. If CGC
14 were to engage in asset management itself, then all of the
15 earnings from this activity would inure to the ratepayers. The
16 corporate veil of segregation for this activity centralizes the
17 expertise for the asset management activities, but it also reaps
18 profits for the shareholder. Ultimately, the TRA should
19 exercise its duty to balance the needs of the ratepayer with just
20 and reasonable rates for the shareholder for every activity of
21 CGC's provisioning of natural gas service. The TRA currently

1 conducts audits of natural gas costs. If CGC were to
2 independently manage their assets, then those management
3 activities could not be immune to audits by the TRA or its audit
4 representative. Again, regardless of who is managing the
5 assets of CGC, the transactions for this activity should be
6 audited at least triennially.

7
8 **Q. Why do you recommend a triennial review process for the**
9 **system capacity of CGC?**

10 A. The system capacity of a LDC is a complex matter, and
11 the natural gas market changes significantly over relatively
12 short periods of time. The development of asset management
13 arrangements in their current form is fairly new. If the recent
14 past is any guide, the way that the industry handles system
15 capacity will continue to change over time. In order for the
16 TRA to continue to monitor the way that LDCs in Tennessee
17 handle their system capacity in relation to the industry and for
18 the benefit of consumers, periodic reviews by experts in the
19 field are needed. Conducting an independent review every
20 three years is a good balance in terms of efficiency on the one
21 hand and thoroughness on the other hand.

1 Q. Does this conclude your testimony?

2 A. Yes.

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BEFORE THE
TENNESSEE REGULATORY AUTHORITY
AT NASHVILLE, TENNESSEE

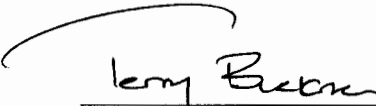
IN RE:

DOCKET TO EVALUATE CHATTANOOGA GAS COMPANY'S GAS PURCHASES
AND RELATED SHARING INCENTIVES

DOCKET NO. 07-00224

AFFIDAVIT

I, Terry Buckner, Regulatory Analyst, for the Consumer Advocate Division of the Attorney General's Office, hereby certify that the attached Direct Testimony represents my opinion in the above-referenced case and the opinion of the Consumer Advocate Division.


TERRY BUCKNER

Sworn to and subscribed before me
this 30th day of May, 2008.


NOTARY PUBLIC

My commission expires: Aug. 23, 2011



My Commission Expires AUG. 23, 2011

Terry Buckner, Regulatory Analyst

B. S. in Business Administration, University of Tennessee, Knoxville

CPA, Member of the AICPA and the Tennessee Society of CPAs

Twenty-five years of experience with the Public Utility industry:

1980 - 1988 TDS Telecom - Region Accounting Manager

1989 - 1994 Tennessee Public Service Commission (“TPSC”) - Regulatory Analyst

1995 - 2001 Office of the Attorney General for the State of Tennessee - Consumer Advocate and Protection Division - Regulatory Analyst

2001- 2004 Comptroller’s Office for the State of Tennessee - Public Utility Audit - Assistant Director

2004 - Present Office of the Attorney General for the State of Tennessee - Consumer Advocate and Protection Division - Regulatory Analyst

Oral and written testimony in numerous rate proceedings before the TPSC and the Tennessee Regulatory Authority. Including the following dockets and/or companies

Dockets

TRA #07-00105 Atmos Energy Corporation

Direct Testimony: <http://www.state.tn.us/tra/orders/2007/0700105cg.pdf>

TRA # 06-00290 Tennessee American Water Company

Direct Testimony: <http://www2.state.tn.us/tra/dockets/0600290.htm>

TRA # 06-00175 Chattanooga Gas Company

Direct Testimony: <http://www2.state.tn.us/tra/dockets/0600175.htm>

TRA # 05-00258 Atmos Energy Corporation

Direct Testimony: <http://www2.state.tn.us/tra/dockets/0500258.htm>

TRA #04-00288 Tennessee American Water Company

Direct Testimony: <http://www.state.tn.us/tra/orders/2004/0400288bm.pdf>

TRA#03-00391 BellSouth

Rebuttal: <http://www.state.tn.us/tra/orders/2003/0300391ci.pdf>

Rebuttal Exhibits: <http://www.state.tn.us/tra/orders/2003/0300391ch.pdf>

TRA #02-00383 Chattanooga Gas Company

<http://www.state.tn.us/tra/orders/2002/0200383m.pdf>

TRA #01-00451 United Telephone Company

<http://www.state.tn.us/tra/orders/2001/0100451w.pdf>

TRA #00-00523 Rural Universal Service

<http://www.state.tn.us/tra/orders/2000/000052316.pdf>

TRA #99-00210 BellSouth Telecommunications, Inc.

TRA #99-00244 BellSouth Telecommunications, Inc.

TRA #98-00559 BellSouth Telecommunications, Inc.

TRA #99-00995 TEC Companies

<http://www.state.tn.us/tra/orders/1999/990099522.pdf>

TRA #98-00626 UTSE

TRA #97-00982 Chattanooga Gas Company

TRA #96-00977 Nashville Gas Company

TPSC #95-02258 United Cities Gas Company

TPSC #95-02116 Chattanooga Gas Company

TPSC #94-02876 BellSouth Telecommunications

PSC #92-13527 South Central Bell - Earnings Investigation for the years 1993-1995 (Copy of Testimony Not Available)

Docket N/A GTE - Rate Filing
(Copy of Testimony Not Available)

#78966

BEFORE THE TENNESSEE REGULATORY AUTHORITY

NASHVILLE, TENNESSEE

December 5, 2006

IN RE:	)	
	)	
SUMMARY OF THE TRANSACTIONS IN	)	DOCKET NO.
CHATTANOOGA GAS COMPANY'S DEFERRED	)	04-00402
GAS COST ACCOUNT FOR THE TWELVE	)	
MONTHS ENDED JUNE 30, 2004 AND THE	)	
COMPUTATION OF ACA FACTOR EFFECTIVE	)	
JANUARY 1, 2005	)	
	)	
CHATTANOOGA GAS COMPANY'S REPORT OF	)	DOCKET NO.
ACTUAL GAS COST AND THE APPLICABLE	)	04-00403
INDEX COST FOR EACH MONTH OF THE PLAN	)	
YEAR ENDED JUNE 30, 2004	)	

ORDER ADOPTING TARIFF REVISIONS

This matter came before Chairman Sara Kyle, Director Pat Miller and Director Ron Jones of the Tennessee Regulatory Authority (the "TRA" or "Authority"), the voting panel assigned to this docket, at a regularly scheduled Authority Conference held on August 23, 2006 for consideration for approval of the tariff revisions filed subsequent to the *Compliance Audit Report of the Actual Cost Adjustment Component of the Purchased Gas Adjustment Rule and Performance-Based Ratemaking Tariff for Chattanooga Gas Company* ("Report"). The panel previously considered the Report, prepared by the TRA's Utility Division ("Audit Staff"), at a regularly scheduled Authority Conference held on November 7, 2005. The panel voted unanimously to accept the audit findings as submitted and to require Chattanooga Gas Company ("CGC" or "Company") to submit to the TRA proposed guidelines for affiliate transactions to deter the risk of preferential treatment of an affiliate over a non-affiliate. These affiliate

guidelines were to be submitted by the Company as part of its performance-based ratemaking tariff no later than December 29, 2005.¹

A revised tariff was considered by the panel at the January 23, 2006 Authority Conference. The panel expressed concern that the proposed affiliate guidelines did not sufficiently cover certain affiliate transactions and clarified that the Company's tariff should include guidelines for securing an asset manager through an RFP procedure that will ensure an affiliate is not given preferential treatment over a non-affiliate.²

Pursuant to the panel's directions, the RFP procedures submitted by CGC in the current tariff revision require the Company to develop a written proposal, advertise that proposal for thirty (30) days, evaluate only written, on-time bids, and maintain all RFP documents for four (4) years. In addition, the guidelines set forth the total value of the bidder's asset management qualifications and experience, and the bidder's financial stability and strength as minimum criteria for evaluating the RFP bids.³

On July 21, 2006, Audit Staff filed a response concurring with the proposed RFP procedures. Audit Staff also explains that currently CGC refunds 100% of the profits earned from its asset management agreement with its affiliate to ratepayers, although the Interruptible Margin Credit Rider ("IMCR") tariff allows the Company to retain 50% of those profits. Audit Staff notes that CGC would likely opt to retain 50% of asset management fees if an agreement is signed with a third party and that the application of the IMCR tariff should be taken into account by the Authority when approving future asset management agreements.⁴

¹ *Order Approving Tariff*, pp. 1-2 (April 24, 2006).

² *Id.* at 3.

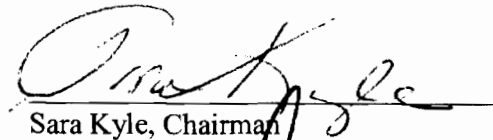
³ *Proposed Tariff Revisions*, pp. 4-5 (July 17, 2006).

⁴ *TRA Staff Response to Chattanooga Gas' Proposed Revision to Gas Tariff No. 1 to Add RFP Procedures for Selection of Asset Manager and/or Gas Provider*, pp. 3-4 (July 21, 2006).

After considering the Report and subsequent tariff revisions at the August 23, 2006 Authority Conference, the voting panel approved and adopted the tariff revisions as discussed above.

IT IS THEREFORE ORDERED THAT:

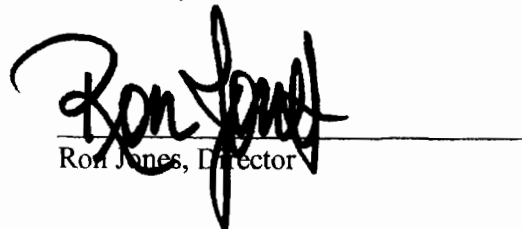
The tariff revisions filed subsequent to the *Compliance Audit Report of the Actual Cost Adjustment Component of the Purchased Gas Adjustment Rule and Performance-Based Ratemaking Tariff for Chattanooga Gas Company* are approved.



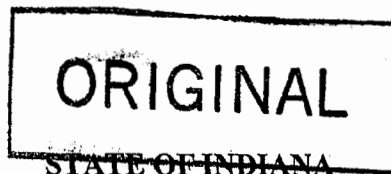
Sara Kyle, Chairman



Pat Miller, Director



Ron Jones, Director



INDIANA UTILITY REGULATORY COMMISSION

VERIFIED JOINT PETITION OF INDIANA GAS)
COMPANY, INC., SOUTHERN INDIANA GAS AND)
ELECTRIC COMPANY AND THE BOARD OF)
DIRECTORS FOR UTILITIES OF THE)
DEPARTMENT OF PUBLIC UTILITIES OF THE)
CITY OF INDIANAPOLIS, AS SUCCESSOR)
TRUSTEE OF A PUBLIC CHARITABLE TRUST,)
d/b/a CITIZENS GAS & COKE UTILITY,)
PURSUANT TO IND. CODE § 8-1-2.5 *et seq.* FOR)
APPROVAL OF AN ALTERNATIVE REGULATORY)
PLAN ESTABLISHING FLEXIBLE TERMS, RATES)
AND CHARGES FOR CERTAIN RETAIL ENERGY)
SERVICES, INCLUDING CONTINUED USE OF A)
GAS COST INCENTIVE MECHANISM AND)
APPROVAL OF NEW SUPPLY AGREEMENTS)
WITH PROLIANCE ENERGY, LLC)

CAUSE NO. 42973

APPROVED: APR 25 2006

BY THE COMMISSION:

Larry S. Landis, Commissioner
William G. Divine, Administrative Law Judge

In March, 1996, Indiana Gas Company, Inc. ("IGC") and the Board of Directors for Utilities of the Department of Public Utilities of the City of Indianapolis, d/b/a Citizens Gas & Coke Utility ("Citizens") agreed upon terms for formation of a gas supply alliance to be jointly owned and governed for purposes of providing gas supply and portfolio administration services to both IGC and Citizens. This jointly owned alliance entity is ProLiance Energy, LLC ("ProLiance").

On September 12, 1997, the Indiana Utility Regulatory Commission ("Commission") issued an Order in Cause No. 40437 finding IGC and Citizens' supply relationship with ProLiance to be in the public interest based on demonstrated cost savings made possible via the joint administration of the utilities' supply portfolios. Certain issues related to the terms for provision of gas supply by ProLiance to the utilities were left to be resolved in a consolidated subdocket proceeding related to the utilities' gas cost adjustments.

On June 4, 2002, the Office of Utility Consumer Counselor ("OUCC"), Citizens Action Coalition ("CAC"), Southern Indiana Gas and Electric Company ("SIGECO"), IGC, Citizens, and a group of SIGECO, IGC and Citizens' industrial customers ("I.G.C.G.-Industrial Group") filed an executed Settlement Agreement in Cause Nos. 42233 and GCA50-S1 proposing a resolution of all outstanding issues related to ProLiance and establishing prospective terms for ProLiance's provision of gas supply services to the Petitioners. ProLiance also signed the 2002 Settlement Agreement to confirm its commitment to certain terms contained therein.

On July 24, 2002, the Commission adopted a final Order in Cause Nos. 42233 and

GCA50-S1 that approved the 2002 Settlement Agreement as in the public interest. The Commission authorized Citizens, IGC and SIGECO to enter into respective gas supply agreements with ProLiance through March 31, 2007.

On December 1, 2005, IGC, SIGECO, Citizens, the OUCC, the I.G.C.G.-Industrial Group and CAC filed in Cause Nos. 42233 and GCA50-S1 their "Third Settlement Status Report and Notice of Agreement in Principle," attaching thereto an Agreement in Principle ("AIP") as Exhibit A. The Settlement Parties indicated in their Status Report that they had reached an agreement regarding settlement of all issues related to IGC, SIGECO and Citizens' continued use of ProLiance as a supplier of gas and related portfolio administration services after March 31, 2007, and intended to file with the Commission for its consideration a formal Settlement Agreement and testimony in support thereof on or about January 31, 2006.

On January 12, 2006, IGC, SIGECO, and Citizens filed with the Commission their Verified Joint Petition, which was docketed as Cause No. 42973. This new alternative regulation plan ("ARP") Petition revises terms of the 2002 Settlement Agreement and ARP approved in Cause Nos. 42233 and GCA50-S1. Those revisions include, but are not limited to, changes regarding transparency of information, profit sharing, capacity release access, supply planning protocol and Affiliate Guideline clarity, compliance and non-discrimination.

On February 1, 2006, IGC, Citizens, SIGECO (hereinafter referred to collectively as the "Petitioners" or "Utilities" and individually as a "Utility"), the OUCC, the I.G.C.G.-Industrial Group, and the CAC executed and filed a Settlement Agreement ("Settlement Agreement") in this Cause. (All of these foregoing parties are hereinafter referred to collectively as the "Parties," while the OUCC, the CAC, and the I.G.C.G.-Industrial Group are hereinafter referred to collectively as the "Consumer Parties.") ProLiance also executed the Settlement Agreement and, while not a party to this Cause, is bound to the extent provided in the Settlement Agreement.

On February 16, 2006, pursuant to public notice duly published as required by law, a Prehearing Conference was held in Room E306 of the Indiana Government Center South, Indianapolis, Indiana. At the Prehearing Conference, the Commission granted a Petition to Intervene that was filed on February 15, 2006, by the I.G.C.G.-Industrial Group. The CAC indicated at the Prehearing Conference its intention to seek intervention. Petitioners, the OUCC, the I.G.C.G.-Industrial Group, and CAC participated in the Prehearing Conference by counsel. The CAC's March 10, 2006 Petition to Intervene was granted at the start of the March 15, 2006 Evidentiary Hearing.

On February 24, 2006, Petitioners filed the Direct Testimony and Exhibits of Jerrold L. Ulrey, LaTona S. Prentice and Paul G. McLean. Also, on February 24, 2006, the OUCC filed the Direct Testimony of Matthew G. Parsell and Jerome D. Mierzwa.

A public Evidentiary Hearing was held in this Cause on March 15, 2006, in Room E306 of the Indiana Government Center South, Indianapolis, Indiana. At this hearing, the Settlement Agreement was submitted into evidence, along with supporting testimony and exhibits. No members of the general public appeared or sought to testify at any stage of these proceedings.

Based upon the applicable law and the evidence of record, the Commission now finds:

1. **Commission Jurisdiction.** Citizens is a municipally owned gas utility subject to the jurisdiction of the Commission under Ind. Code § 8-1-11.1-1, *et seq.*, a “gas utility” within the meaning of Ind. Code § 8-1-2-42(g), and an “energy utility” within the meaning of Ind. Code § 8-1-2.5-2. Citizens distributes to the public natural gas, and provides gas delivery services to its eligible customers. Citizens provides adequate and efficient gas service to its customers by means of gas utility plant, properties, equipment and facilities owned, operated, managed and controlled by it, which are used and useful for the convenience of the public. Citizens’ gas plant includes transmission, distribution, liquefied natural gas storage facilities in Marion County, Indiana and underground natural gas storage facilities in Greene County, Indiana. Citizens provides gas service to approximately 262,137 residential, commercial, and industrial customers in and around Marion County, Indiana.

IGC is an operating public utility incorporated under the laws of the State of Indiana. It is a “public utility” and a “gas utility” within the meaning of those terms as used in the Public Service Commission Act, as amended, and is subject to the jurisdiction of this Commission in the manner and to the extent provided by the laws of the State of Indiana. IGC is also an “energy utility” within the meaning of Ind. Code § 8-1-2.5-2. It has charter power and authority to engage in, and is engaged in the business of rendering gas distribution service solely within the State of Indiana under indeterminate permits, franchises, and necessity certificates heretofore duly acquired. It owns, operates, manages, and controls, among other things, plant, property equipment, and facilities which are used and useful for the production, storage, transmission, distribution and furnishing of gas service to approximately 542,769 ultimate consumers in 311 communities and adjacent rural areas in 49 counties in the north central, central, and southern portions of Indiana.

SIGECO is an operating public utility incorporated under the laws of the State of Indiana. It is a “public utility” and a “gas utility” within the meaning of those terms as used in the Public Service Commission Act, as amended, and is subject to the jurisdiction of this Commission in the manner and to the extent provided by the laws of the State of Indiana. SIGECO is also an “energy utility” within the meaning of Ind. Code § 8-1-2.5-2. It has charter power and authority to engage in, and is engaged in the business of rendering both gas and electric public utility service in the State of Indiana and owns, operates, manages and controls, among other things, plant and equipment within the State of Indiana used for the production, transmission, delivery and furnishing of such service to approximately 132,611 ultimate electric customers and 155,000 ultimate gas customers in southwestern Indiana.

2. **Alternative Regulatory Plan (“ARP”).** On January 12, 2006, the Utilities filed their Verified Joint Petition initiating this proceeding under Ind. Code § 8-1-2.5 *et seq.* The Petition requests approval of an ARP establishing flexible terms, rates and charges for certain retail energy services, including continued use of a gas cost incentive mechanism, and approval of new gas supply agreements with ProLiance. The Settlement Agreement filed on February 1, 2006, revises terms of the 2002 Settlement Agreement and ARP approved in Cause Nos. 42233 and GCA50-S1.

In their Petition, the Utilities identified the following specific provisions of the Settlement Agreement as constituting their ARP for purposes of Commission review and consideration: (a) information transparency, (b) Utility supply planning, (c) Affiliate Guidelines and non-discrimination, (d) entitlement utilization, (e) profit sharing mechanism, (f) entitlement

value sharing, (g) joint administration of benefits, (h) Settlement Agreement review, (i) audit costs, and (j) a defined term for the ARP commencing upon Commission approval and extending until March 31, 2011, pursuant to Ind. Code § 8-1-2.5-7. The Commission's approval of the ARP will result in modification of the Commission's application to the Utilities of Ind. Code § 8-1-2-42(g), and other applicable statutes, solely in order to effect the terms of the Settlement Agreement and the Utilities' recovery of gas costs consistent therewith. The Utilities further indicated in the Petition that they would submit their new gas supply agreements with ProLiance for Commission approval.

In their Petition, the Utilities suggest that Commission approval of the ARP will permit them to coordinate their gas supply efforts in an efficient manner, which will benefit the Utilities, their respective customers and the State consistent with the terms of the AIP. The Utilities also suggest that their ARP(s) will provide cost benefits derived from the joint administration of supply; will in certain instances reward performance; will, as a whole, promote the efficient provision of retail energy services; will share certain profits; and are consistent with the public interest.

3. The Settlement Agreement. Settlements presented to the Commission are not ordinary contracts between private parties. *United States Gypsum, Inc. v. Indiana Gas Co.*, 735 N.E.2d 790, 803 (Ind. 2000). When the Commission approves a settlement, that settlement "loses its status as a strictly private contract and takes on a public interest gloss." *Id.* (quoting *Citizens Action Coalition v. PSI Energy*, 664 N.E.2d 401, 406 (Ind. Ct. App. 1996)). Thus, the Commission "may not accept a settlement merely because the private parties are satisfied; rather [the Commission] must consider whether the public interest will be served by accepting the settlement." *Citizens Action Coalition*, 664 N.E.2d at 406.

Furthermore, any Commission decision, ruling, or order – including the approval of a settlement – must be supported by specific findings of fact and sufficient evidence. *United States Gypsum*, 735 N.E.2d at 795 (citing *Citizens Action Coalition v. Public Service Co.*, 582 N.E.2d 330, 331 (Ind. 1991)). The Commission's own procedural rules require that settlements be supported by probative evidence. 170 IAC 1-1.1-17(d). Therefore, before the Commission can approve the Settlement Agreement, we must determine whether the evidence in this Cause sufficiently supports the conclusions that the Settlement Agreement is reasonable, just, and consistent with the purpose of Indiana Code § 8-1-2, and that such agreement serves the public interest.

As described by the Settlement Agreement, the Parties have negotiated in good faith in order to reach agreement on terms designed to preserve the benefits of joint administration of the Utilities' supply portfolios by ProLiance, while at the same time addressing key concepts to assure fair allocation of benefits and review of information. These "key concepts" include (1) transparency of information, (2) profit sharing, (3) capacity release access, (4) supply planning protocol, and (5) Affiliate Guideline clarity, compliance and non-discrimination. As noted by Petitioners' Witness Ulrey, the Settlement Agreement provides large customers and marketers with non-discriminatory access to a large portion of the Utilities' available unused long haul pipeline entitlements, and both preserves the benefits from the joint administration of the Utilities' supply portfolios and allocates those benefits in a manner that significantly reduces customers' costs. (Ulrey Testimony p. 6.) Mr. Ulrey notes that, under the Settlement Agreement, ProLiance will provide supply services to the Utilities through March 31, 2011, and

review processes are put in place to allow for proper transparency of data and prescribed audits by the OUCC. (*Id.* p. 7.)

Based on this general understanding of the Settlement Agreement, we will separately discuss each of the main components of the Settlement Agreement below. As in our July 24, 2002 Order in Cause No. 42233 and GCA50-S1, we find it significant that all three consumer representatives, including the OUCC as the statutory representative of the interests of customers, are signatories to the Settlement Agreement and support approval of its terms as being in the public interest.

a. Information Transparency. Under Article I of the Settlement Agreement, ProLiance and the Utilities agree to provide the OUCC with full access to all data reasonably related to ProLiance's services under the agreed arrangements. The OUCC will have free and open access to all ProLiance books and records reasonably relating to the service provided for in the Settlement Agreement. The OUCC will be permitted to discuss all relevant data with ProLiance and respective Utility personnel, subject to agreed confidentiality protections. To further review of such data, the Utilities, under Article IX, will fund up to \$125,000 each year in costs related to the OUCC's use of external auditors. Under Article II, the coordination of resources to provide services to the Utilities, as well as the Supply Planning process, will be transparent, and the OUCC will be able to monitor all aspects of the Utilities' process, as well as all support and assistance provided by ProLiance. As noted by OUCC Witness Parsell, the Settlement Agreement brings significant improvements in the area of transparency of information. (*See Parsell Testimony p. 7.*) During the hearing, the Commission inquired whether any of the parties objected to the Commission staff being provided full access to all data reasonably related to ProLiance's services, which is being provided to the OUCC. The parties indicated on the record that the same access to this information was acceptable so long as the parties' confidentiality concerns were satisfied.

b. Utility Supply Planning. Article II of the Settlement Agreement provides that the Utilities will be the "owner" of the supply planning process, including maintaining sole, final decision-making authority with respect to their individual supply plans. The Utilities will follow the supply planning procedures set forth in Appendix F to the Settlement Agreement. Appendix F provides for the Utilities to work directly with each other in a collaborative effort to optimize the Utilities' supply resources in order to create synergies, where possible, to reduce costs. The Utilities may include ProLiance in such efforts. Each Utility will provide timely, detailed demand forecast data and analysis to ProLiance to enable it to investigate, develop and implement demand cost savings strategies. The Utilities will not, however, delegate their supply planning responsibilities to ProLiance but may use consultants, including ProLiance, to support supply planning analysis and implementation. Witness Prentice observed that the supply planning process will be transparent, with the OUCC (or its auditor) able to monitor all aspects of the process, including ProLiance's role. (*Prentice Testimony p. 9.*) The Commission finds that the Settlement Agreement provides for an effective supply planning process which is important to the provision of reliable and economical utility service.

c. Modified Supply Agreements. Under Article III, from the date of Commission approval of the Settlement Agreement through March 31, 2011, the supply

relationships between each of the Utilities and ProLiance will be subject to new gas supply agreements with elements described in the Settlement Agreement. The terms of the new agreements will be in the form set forth in Appendices A, B and C. The attachments to the forms of gas supply agreements identified as Appendices A, B and C set forth specific price and service terms for each delivery service provided to the Utilities. Our approval of the Settlement Agreement includes approval of the forms of new supply agreements, attached to the Settlement Agreement, as being in the public interest. The Commission notes certain material terms of the new supply agreements below:

1. *Commodity.* Commodity is to be separately purchased for each Utility, subject to the provisions set forth in Appendix E, which includes guidelines related to a Gas Cost Incentive Mechanism (GCIM), as well as a Price Volatility Mitigation Program (PVMP).

2. *Delivery Services to the Utilities.* ProLiance is to sell delivery services necessary for the Utilities to provide gas supply to their customers. ProLiance is expected to provide delivery entitlements at a savings compared to what the Utilities could achieve individually, without the benefit of the joint portfolio administration. The Utilities' customers and ProLiance will share the benefit of such economies or "synergies." Following a review process conducted by the OUCC, the Utilities and ProLiance, the synergies and efficiencies associated with the joint portfolio of interstate pipeline transportation and storage services will be shared on a 50/50 basis through the establishment of an annual demand cost cap, which is an amount negotiated by the OUCC and ProLiance.

Witness Ulrey observed that under portions of the Settlement Agreement setting forth material terms of the new supply agreements, customers will benefit directly. (Ulrey Testimony p. 7.) He testified that customers receive 50% of the pipeline demand cost synergies created as a result of the joint administration of the Utilities' supply portfolios, and that, with limited exceptions, such costs will be capped, thereby transferring risk of cost increases to ProLiance. (*Id.* pp. 7-8.) He also observed that customers will continue to share in the benefits of cost savings on commodity purchases via a GCIM. (*Id.* p. 8.) Witness Prentice explained that, under the Settlement Agreement, drafts of the proposed appendices to the Gas Supply Agreements will be reviewed by the Consumer Parties prior to filing them with the Commission, and the Consumer Parties have reserved the right to object to the proposed appendices, if necessary. (Prentice Testimony p. 6.)

- d. Entitlement Utilization. Under Article IV, the Utilities' available unused entitlements will be divided into equal halves, with 50% of anticipated unused entitlements, as determined by the Utilities' supply plans, retained by ProLiance, subject to the Profit Sharing Mechanism described in the Settlement Agreement. The 50% of anticipated unused entitlements not retained by ProLiance will be offered for sale by the Utilities through a bidding process administered by Utility personnel, maintaining a clear separation from ProLiance's operations. The procedures for release of anticipated unused entitlements are set forth in Appendix D to the Settlement Agreement. This process should result in proceeds to offset gas sales customers' costs, while also providing non-

discriminatory access to available capacity. According to Witness Ulrey, customer costs will be reduced by a large share of the revenues received through the sale of the Utilities' available unutilized long haul pipeline entitlements. (Ulrey Testimony p. 8.) The procedures set forth in Appendix D are designed to promote the following goals: (i) to promote competition, (ii) to provide nondiscriminatory open access, (iii) to generate the highest economic value consistent with reliable supply, and (iv) to provide necessary transparency. OUCC Witness Parsell observed that the Settlement Agreement provides what the OUCC believes to be a capacity release program designed to obtain increased value for transport entitlements from the marketplace. (See Parsell Testimony p. 7.) Overall, the OUCC believes that the capacity release program provides superior benefits to the end-use customers. (*Id.* p. 8.)

e. Profit Sharing. The 2002 Settlement Agreement did not contain a profit sharing arrangement. (McLean Testimony p. 3.) The 2002 Settlement Agreement established a capacity auction, resolving the issues of access to those pipeline entitlements, as well as allocation of the proceeds from use of that capacity. (Ulrey Testimony p. 8.) Although the auction process provided the desired access to the Utilities' available capacity in a non-discriminatory manner, it also represented a relatively passive means of obtaining value from those entitlements. (*Id.* at p. 9.) Article IV of the proposed Settlement Agreement now includes a profit sharing mechanism. The Settlement Agreement attempts to create more value from the sale of the Utilities' unused long haul pipeline capacity for customers, while still providing access to that capacity. (*Id.*) Under the Settlement Agreement, half of the capacity will be offered for sale by the Utilities through a pre-arranged sales process that will solicit bids, and it is generally believed that the process will generate more competitive bids than an auction posting process. (*Id.*) Customers receive 85% of the value from the sale of that portion of the capacity. (*Id.*)

The other half of the capacity is to be retained by ProLiance, which will then market that capacity. (*Id.*) The parties have agreed to an initial value for this portion of the unused capacity, which results in a customer benefit of \$5.1 million per year. This value will begin the first month following Commission approval and will be used through October 31, 2007. (*Id.*) Thereafter, customers are to receive 75% of the value of that capacity as determined using a benchmark formula consistent with Appendix G of the Settlement Agreement. (*Id.*)

Appendix G sets forth the terms under which ProLiance's use of a portion of the projected available pipeline entitlements will generate benefits to be shared with customers. (McLean Testimony p. 3.) Appendix G represents a compromise between ProLiance and the OUCC in the initial determination of unused pipeline entitlements value for the purpose of the Settlement Agreement. (*Id.*) The intent of Appendix G is to provide ratepayers with a share of the value generated by ProLiance from unused entitlements. (Mierzwa Testimony p. 17.)

As defined in Appendix G, the "Measurement Year" extends from November 1, 2006 to October 31, 2007. (McLean Testimony p. 7.) For that Measurement Year, ProLiance will provide information to the OUCC regarding values for projected unused pipeline entitlements and actual unused pipeline entitlements on at least a quarterly basis,

beginning with the quarter commencing July 1, 2006. (*Id.*) Appendix G sets forth a process to evaluate, calculate, and share value after the Measurement Year by taking certain defined actual market sales and deducting certain applicable costs. (*Id.*) This process should result in a negotiated fixed amount to apply for the remainder of the period under the Settlement Agreement. (*Id.*) Appendix G includes deadlines for the parties to exchange information and value calculations, and to ultimately reach agreement on the value going forward. If the parties are not successful in their negotiations, either party may seek a decision from the Commission regarding the appropriate value to be shared, consistent with the Settlement Agreement. (*Id.*)

As noted by OUCC Witness Parsell, the Settlement Agreement brings significant improvements in the area of profit sharing. (Parsell Testimony p. 7.) According to Witness Prentice, the parties intend that the provisions in the Settlement Agreement relating to the Utilities' unused pipeline entitlements will increase the level of benefits received by customers. (Prentice Testimony p. 11.) She notes that this revised process also is more consistent with current market practices. (*Id.*) The Commission finds that the Profit Sharing Mechanism in the Settlement Agreement increases the potential level of benefits received by customers, which is in the public interest.

f. Affiliate Guidelines and Non-Discrimination. Under Article V of the Settlement Agreement, the Utilities have agreed to continue to comply with the Affiliate Guidelines set forth in Appendices H and I. The parties to the Settlement Agreement also have agreed to work together and in good faith to interpret the provisions of the Settlement Agreement and Affiliate Guidelines. Appendix J further provides for potential alternative methods to resolve disputes.

g. Customer Education. The Utilities have agreed in Article VI to conduct focused educational and publicity efforts, directed both to customers and to potential competitors, to explain the process for offering for sale the Utilities' available entitlements via the pre-arranged offering and the auction process.

h. Joint Administration of Benefits. The 2002 Settlement Agreement did not provide for any contribution to low-income assistance programs in 2006. (*See* Ulrey Testimony p. 7.) Article VII of the proposed Settlement Agreement provides that, contingent on ProLiance's continued administration of gas supply for the Utilities, \$2 million will be contributed in 2006 to ratepayer programs that have been selected by the Utilities, after consultation with the OUCC. This contribution continues each year ProLiance provides supply to the Utilities through 2010, with a pro rata payment made for 2011. Each year, ten percent of the annual contribution will be allocated as a grant to the Indiana Utility Rate Payer Trust and the remaining ninety percent will be allocated to low-income programs. We find the foregoing amounts to be a benefit to customers and in the public interest.

i. Settlement Agreement Review. Article VIII provides for meetings of the Settlement Parties to review the Entitlement Auction Process and the operation of the Profit Sharing Mechanism benchmarks. By agreement of the signatories, there may be adjustments to improve such processes, consistent with the overall agreement of the signatories, through a process subject to Commission oversight and approval.

j. Audit Costs. Under Article IX, on a semi-annual basis, books, records and data reasonably related to the provisions of the Settlement Agreement may be formally reviewed by the OUCC. In the event the OUCC employs an outside auditor or consultant to assist in the review process, the Utilities will pay up to \$125,000 each year, including a carryover provision for unused review expenses, which amount may be used to offset the OUCC's reasonable costs specifically incurred for the review.

k. Duration of Supply Relationship. Under Article X, ProLiance will provide gas supply services for a term beginning April 1, 2006 (or the first month following the date of approval of the Settlement Agreement by the Commission) and ending March 31, 2011.

Witness Ulrey explained that at least eleven months prior to the expiration of the supply agreements, the Utilities and Consumer Parties would commence discussions regarding potential new service terms. In the absence of an agreement on new terms, no later than October 1, 2010, the Utilities may file a proposal with the Commission to continue to obtain gas supply and portfolio administration services from an affiliate. (Ulrey Testimony p. 13.) Such a proposal would be subject to a public interest review, and if the parties reach an agreement, that agreement also would be filed with the Commission for its review and approval. (*Id.*) We find that the parties have appropriately made provision for what will occur at the end of the term of the new supply agreements.

The Settlement Agreement contains various other provisions, and we note with approval that certain areas addressed in the 2002 Settlement Agreement are similarly addressed in the Settlement Agreement. We note specifically that the 2002 Settlement Agreement included a section on enforcement of the settlement provisions, and the proposed Settlement Agreement has adopted the enforcement section in its entirety at Article XI.

4. Approval and Effect of Settlement Agreement. Based on our review of the Settlement Agreement and the evidence in support thereof, we find that the terms negotiated by the Utilities and Consumer Parties are reasonable, supported by sufficient evidence, in the public interest, and should be approved. The testimony of Witnesses Ulrey, Prentice and Parsell each described various aspects of the Settlement Agreement and indicates their respective opinions that the Settlement Agreement is in the public interest. We note and are encouraged by Witness Prentice's assessment that the Settlement Agreement serves the public interest for the following reasons:

- The cost benefits of the Utilities' supply alliance will continue to reduce customer costs.
- The Settlement Agreement preserves the joint administration of the Utilities' gas supply and increases the level of benefits provided to customers.
- In view of the current environment of volatile wholesale gas prices, the Settlement Agreement addresses the largest component of customer bills with an array of enhanced cost savings mechanisms.

- Customers will receive half of the pipeline Demand Costs synergies created as a result of the joint administration of the Utilities' supply portfolios.
- The Settlement Agreement will result in a greater reduction of customer costs through their receipt of a larger share of the revenues achieved through the sale of the Utilities' available unused pipeline entitlements.
- The Settlement Agreement preserves the GCIM process, under which cost savings on commodity purchases are shared with customers. (Prentice Testimony p. 13)

Our approval of this Settlement Agreement includes the necessary approval of the Utilities' ARP, which has been submitted in order to effectuate certain designated portions of the Settlement Agreement and shall be construed consistent therewith. The Parties have agreed that the Settlement Agreement should not be used as precedent in any other proceeding or for any other purpose, except to the extent necessary to implement or enforce its terms. Consequently, with regard to future citation of the Settlement Agreement, we find that our approval herein should be construed in a manner consistent with our finding in *Richmond Power & Light*, Cause No. 40434, approved March 19, 1997.

We find it appropriate that, shortly following the issuance of this Order, Party and Commission representatives should conduct one or more workshops to discuss implementation of the terms of the Settlement Agreement.

IT IS THEREFORE ORDERED BY THE INDIANA UTILITY REGULATORY COMMISSION that:

1. The Settlement Agreement filed in this Cause on February 1, 2006, is hereby approved. A copy of the Settlement Agreement is attached to, and incorporated into, this Order.
2. Citizens, IGC and SIGECO are authorized to enter into new gas supply agreements consistent with the Settlement Agreement in the form filed as Appendices A, B and C. Copies of the executed gas supply agreements, including the attachments thereto in executed form, shall be filed with the Commission under Ind. Code § 8-1-2-49, as contemplated by the Settlement Agreement. Any subsequent revisions or amendments to the appendices attached to the new gas supply agreements also shall be filed with the Commission pursuant to and consistent with the Settlement Agreement and Ind. Code § 8-1-2-49.
3. Consistent with the terms of the Settlement Agreement, the proposed ARP filed by Citizens, IGC and SIGECO is approved and the Commission's regulation of the Utilities' gas costs shall be modified consistent with those terms until its termination on March 31, 2011.
4. Party and Commission representatives shall conduct one or more workshops to discuss implementation of the terms of the Settlement Agreement.

5. In accordance with Ind. Code § 8-1-2-70, Citizens shall pay the following charges within twenty (20) days from the date of the Order to the Secretary of the Commission:

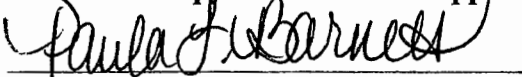
Commission Charges	\$200.00
Reporting Charges	\$ 39.41
Legal Advertising Charges	\$127.15
OUCC Charges	<u>\$380.00</u>

TOTAL \$746.56

6. This Order shall be effective on and after the date of its approval.

HARDY, HADLEY, SERVER AND ZIEGNER CONCUR; LANDIS ABSENT:
APPROVED: APR 25 2006

I hereby certify that the above is a true
and correct copy of the Order as approved.



Paula L. Barnett
Acting Secretary to the Commission

STATE OF INDIANA
INDIANA UTILITY REGULATORY COMMISSION

VERIFIED JOINT PETITION OF INDIANA)
GAS COMPANY, INC., SOUTHERN)
INDIANA GAS AND ELECTRIC COMPANY)
AND THE BOARD OF DIRECTORS FOR)
UTILITIES OF THE DEPARTMENT OF)
PUBLIC UTILITIES OF THE CITY OF)
INDIANAPOLIS, AS SUCCESSOR)
TRUSTEE OF A PUBLIC CHARITABLE)
TRUST, d/b/a CITIZENS GAS & COKE)
UTILITY, PURSUANT TO IND. CODE § 8-)
1-2.5 et. seq. FOR APPROVAL OF AN)
ALTERNATIVE REGULATORY PLAN)
ESTABLISHING FLEXIBLE TERMS,)
RATES AND CHARGES FOR CERTAIN)
RETAIL ENERGY SERVICES, INCLUDING)
CONTINUED USE OF A GAS COST)
INCENTIVE MECHANISM AND)
APPROVAL OF NEW SUPPLY)
AGREEMENTS WITH PROLIANCE)
ENERGY, LLC)

FILED

FEB 01 2006

INDIANA UTILITY
REGULATORY COMMISSION

CAUSE NO. 42973

IURC
PETITIONER'S

EXHIBIT NO.

3-15-06

DATE

REPORTER

SETTLEMENT AGREEMENT

This Settlement Agreement ("Settlement") is entered into this 1st day of February, 2006, between and among duly authorized representatives of Indiana Gas Company, d/b/a Vectren Energy Delivery of Indiana, Inc. ("Vectren North"), the Board of Directors for Utilities of the Department of Public Utilities of the City of Indianapolis, as Successor Trustee of a Public Charitable Trust, d/b/a Citizens Gas & Coke Utility ("Citizens"), Southern Indiana Gas & Electric Company, d/b/a Vectren Energy Delivery of Indiana, Inc. ("Vectren South") (Vectren North,

Vectren South and Citizens are collectively referred to as the "Utilities", and each individually as a "Utility"), the Indiana Office of Utility Consumer Counselor ("OUCC"), I.G.C.G.-Industrial Group ("I.G.C.G.-Industrial Group," consisting of Belden CDT Inc., General Motors Corporation, Reilly Industries, Inc., Rolls-Royce Corporation and Smurfit-Stone Container Corporation), and The Citizens Action Coalition of Indiana, Inc. ("CAC"). The foregoing parties are referred to collectively as the "Parties." ProLiance Energy, LLC ("ProLiance"), while not a Party to the captioned proceeding, is a signatory to the Settlement and is bound to the extent provided for herein. The Parties and ProLiance are referred to collectively as the "Signatories."

WHEREAS, on June 4, 2002, the Parties filed a settlement agreement with the Commission setting forth terms and conditions for the provision of gas supply services from ProLiance to Citizens, Vectren North and Vectren South from the date of the Commission's approval of the settlement agreement through March 31, 2007, thereby settling all outstanding issues in the Utilities' GCA proceedings and in Cause No. 42233 (the "GCA50 Settlement");

WHEREAS, the GCA50 Settlement also addressed the administration of the Utilities' gas supply functions beyond March 31, 2007, by setting forth certain potential options to be selected by the Utilities;

WHEREAS, prior to the Utilities selecting one of the alternative options, the Parties entered into negotiations regarding the potential for ProLiance to continue to jointly administer the gas supply portfolios of the Utilities, such

negotiations culminating in the Parties filing an Agreement in Principle with the Commission on December 1, 2005, setting forth agreement on key concepts, including: (1) Transparency of Information, (2) Profit Sharing, (3) Capacity Release Access, (4) Supply Planning Protocol, and (5) Affiliate Guideline clarity, compliance and non-discrimination;

WHEREAS, the Parties have negotiated in good faith in order to reach agreement on terms designed to preserve the benefits of the joint administration of the Utilities' supply portfolios while addressing the key concepts set forth above to assure fair allocation of benefits and review of information;

WHEREAS, on January 12, 2006 the Utilities filed a joint petition with the Commission under I.C. § 8-1-2.5 in order to effectuate the Commission's review of this Settlement and, if found in the public interest, the approval of this Settlement to permit the Parties to modify the current supply agreements between ProLiance and the Utilities by April 1, 2006 consistent with the agreed upon provisions of the Settlement;

NOW, THEREFORE, the Parties, contingent on Commission approval, make this agreement in accordance with and subject to the following provisions:

Article I

Information Transparency

1.1 Subject to protection of confidential information as necessary, ProLiance and the Utilities agree to provide the OUCC and its agents with full

access to all data reasonably related to ProLiance's services under the agreed arrangements. This information will include data related to ProLiance's services to the Utilities, as well as data associated with the Profit Sharing Mechanisms described herein, including the data reasonably related to ProLiance's sales or disposition of supply resources held in connection with its services to the Utilities. The OUCC will have free and open access to all ProLiance books and records reasonably relating to the service provided for in the Settlement. The OUCC may retain outside consultants to monitor, consult and audit ProLiance's activities under the Settlement, on terms set forth in Article IX below.

1.2 ProLiance will provide information on the pipeline transportation and storage contracts that enable meeting delivery obligations to the Utilities. These resources will be reviewed in the demand cost review process described hereinafter, and at that time contract allocations (in full or in part to each of the Utilities) will be identified. ProLiance also will provide information to the transaction level of detail for industrial and commercial sales on pipelines which deliver to the Utilities, under the agreed arrangements.

1.3 The OUCC shall be able to discuss all such data referenced in this Article with ProLiance and respective Utility personnel, and with any outside consultant retained by the OUCC, who does not own, operate or work for a competitor of ProLiance, subject to agreed confidentiality protections.

Article II

Utility Supply Planning

2.1 The Parties agree that an effective supply planning process, including accurate and independent estimates of demand and the proper determination of the need for and use of supply resources, is materially important to the provision of reliable and economical utility service. The Utilities will be the "owner" of the supply planning process, including maintaining sole, final decision making authority with respect to their individual supply plans.

2.2 The Utilities are not prohibited from using consultants, including ProLiance, to support supply planning analysis and implementation, but in no event will supply planning responsibility be completely delegated to ProLiance. With regard to daily supply planning, a Utility may request ProLiance to run planning models and otherwise assist in determining its supply requirements, but the Utility will independently analyze, approve and be responsible for all of its supply plans. With respect to the Utilities' annual and other long term planning processes, the Utilities shall determine their own supply requirements and independently prepare their own plans for the level and type of supply resources required for system supply.

2.3 The Utilities will work collaboratively, and may include ProLiance, to optimize the Utilities' supply resources in order to create synergies where possible to reduce costs, and may consult with ProLiance in that regard, provided there is no delegation of supply planning responsibility. Each Utility will provide timely, detailed demand forecast data and analysis to ProLiance to enable ProLiance to investigate, develop and implement demand cost savings strategies.

2.4 The coordination of resources to provide services to the Utilities, as well as the Supply Planning process, shall be transparent, with the OUCC able to monitor all aspects of the Utilities' process and all support and assistance provided by ProLiance. The OUCC may use an outside auditor to assist in its review, under agreed confidentiality protections.

2.5 The Utilities will follow the supply planning procedures set forth in Appendix F, which is incorporated herein by reference.

Article III

Modified Supply Agreements

3.1 From the Settlement approval date through March 31, 2011, the supply relationships between each of the Utilities and ProLiance will be subject to new gas supply agreements with the elements described below. The terms of the new agreements will be in the form set forth in Appendices A, B and C, which are incorporated herein by reference. The Commission's approval of the Settlement also will include approval of the attached forms of new supply agreements as being in the public interest. The respective executed attachments to Appendices A, B and C, which set forth specific price and service terms for each delivery service provided to the Utilities, will be filed with the Commission as part of the executed supply contracts within thirty (30) days after approval of the Settlement. With respect to the initial set of such attachments, as well as any updates, renewals or revisions as may be necessary and appropriate through March 31, 2011, the Utilities will serve copies of the proposed attachments on the

OUCG and I.G.C.G.-Industrial Group at least fifteen days prior to filing with the Commission, and will indicate at the time of filing whether any objection has been raised by either of these Parties. Absent an objection, the attachments will become effective upon filing. In the event of an objection, the attachments will become effective at such time and on such terms as the Commission may determine. In the event an objection is made to a revised attachment which otherwise has expired by its terms, the Utility shall continue to receive service under the expired appendix until such time as the Commission resolves the objection. In accordance with Section 3.3, Commission approval of the initial attachments, and updates, renewals or revisions to the attachments does not supersede or otherwise modify or limit any rights, responsibilities or obligations of the Utilities under the GCA process to continue to provide reliable service and to present and support the reasonableness of any costs incurred.

3.2 ProLiance is a Signatory of this Settlement to confirm its agreement to be bound by the terms of Sections 1.1, 1.2, 1.3, 2.2, 2.3, 2.4, 3.1, 3.4(1), 3.4(2), 4.1, 4.2, 4.4, 4.6, 4.7, 4.8, 4.9, 5.2, 8.1, 10.1, 11.10, 11.11, 11.12, 13.1, 13.2, 14.1, 14.4, 15.1, 15.2, 15.3, 15.4 and 15.5 hereof. However, ProLiance's execution of this Settlement for these purposes will not make it a public utility and will not enlarge the scope and extent of the Commission's regulation of its activities. The Utilities will remain responsible for all compliance issues related to the Settlement.

3.3 Upon Commission approval of the Settlement, prospective gas costs incurred as a direct result of the Settlement and new supply agreements

will be fully reported in, and presumed reasonable and recoverable in, the Utilities' GCAs. This Settlement is not intended to supersede or otherwise modify or limit any rights, responsibilities or obligations of the Utilities under the GCA process to continue to provide reliable service and to present and support the reasonableness of any costs incurred.

3.4 Certain material terms of the new supply agreements are set forth below, and, in the event of any conflict or ambiguity between these terms and those set forth in Appendices A, B and C, then these terms shall govern for all regulatory purposes.

- (1) Commodity. Commodity will be separately purchased for each Utility subject to the provisions set forth in Appendix E, which is incorporated by reference. Appendix E includes guidelines related to a Gas Cost Incentive Mechanism (GCIM) as well as a Price Volatility Mitigation Program (PVMP). Both the GCIM and PVMP were previously approved by the Commission as part of the GCA50 Settlement, and have been relied upon by the Utilities in making their commodity purchases. The GCIM will be an approved utility incentive plan, with full reporting in the GCA and a pass through of the allocated share of benefits to customers in the GCA. The reasonableness of terms for all purchase transactions will be reviewable in the Utilities' respective GCAs, but such review will be consistent with the approved terms of the GCIM. The method of tracking and segregation of the Utility commodity portfolios from the rest of ProLiance's portfolio shall be subject to thorough review, audit, scrutiny and enforcement. The

Utilities may pass their share of the risks and rewards from operation of the GCIM to ProLiance in order to provide suitable incentive for ProLiance to beat the GCIM benchmark.

- (2) Delivery Services to the Utilities. ProLiance will sell delivery services necessary for the Utilities to provide gas supply to their customers. ProLiance is expected to provide delivery entitlements at a savings compared to what the Utilities could achieve individually without the benefit of the joint portfolio administration. The Utilities' customers and ProLiance will share the benefit of such economies or "synergies." Synergies and efficiencies associated with the joint portfolio of interstate pipeline transportation and storage services will be shared on a 50/50 basis through the establishment of an annual demand cost cap, following a review process conducted by the OUCC, the Utilities and ProLiance.

The Parties recognize the Annual Demand Cost Cap will be an amount negotiated by the OUCC and ProLiance. The negotiations will consider a number of factors including the negotiated synergies, the market value of the services provided by ProLiance, and ProLiance's costs in providing the services to the Utilities. The lower negotiable limit of the Annual Demand Cost Cap shall be the agreed upon ProLiance cost of providing the services. The upper negotiable limit of the Annual Demand Cost Cap shall be the estimated replacement market value of services provided by ProLiance to the Utilities. The OUCC is not bound by ProLiance's quantification of market value of the services provided to the Utilities or of

allocated costs associated with services provided to the Utilities and may audit those analyses and present differing opinions.

The existing Annual Demand Cost Cap and Demand Cost Sharing established pursuant to the GCA50 Settlement will remain in place until April 1, 2007. At least 180 days prior to April 1, 2007, ProLiance, the Utilities, and the OUCC will meet to discuss and seek agreement on an Annual Demand Cost Cap, based upon the actual portfolio to be used to serve the Utilities, beginning April 1, 2007 and extending through March 31, 2009. With respect to establishing a revised Annual Demand Cost Cap for the period from April 1, 2009 to March 31, 2011, the process detailed below will be repeated with corresponding date changes.

In the absence of agreement between the OUCC and ProLiance to the Annual Demand Cost Cap for either period, either Party may submit its respective quantifications of synergies to the Commission for determination of the Annual Demand Cost Cap. Upon agreement concerning the Annual Demand Cost Cap, any changes in ProLiance's actual costs subsequent to April 1, 2007 will not impact the Utilities' costs for ratemaking purposes, which will remain at the same level during the applicable two year period with the only possible adjustments to those costs for any of the Utilities resulting from the occurrence of one or more of the following contingencies: (a) a pipeline rate case resulting in a tariff rate change of at least five percent (5%), on a cumulative basis, of the tariff demand rate in effect on the dates stated above for the affected

Utility; (b) a pipeline Force Majeure event that affects capacity required to meet Utility demand; (c) a change in the quality or character of service supplied by a pipeline pursuant to a FERC-approved tariff change that results in a changed set of charges or the need for a changed set of services; (d) a change in Utility demand requiring a changed set of services resulting from reconfiguration of on-system supply sources; (e) annual demand or overall peak day changes resulting from changes to a Utility's supply plan which meet or exceed five percent on a cumulative basis of the demand or peak day level as it exists on the date of approval of the Settlement; (f) the need to add pipeline costs consistent with building gas supply infrastructure. Further, such contingencies must be shown actually to have a material cost impact on ProLiance after netting against any other positive and negative impacts. Any adjustment will be made "dollar for dollar" to the total annual portfolio demand costs of the applicable Utility and to the applicable delivery service demand cost. Absent the occurrence of a contingency resulting in an adjustment to the Utilities' demand costs, ProLiance will retain any pipeline rate case refunds associated with services provided to the Utilities between April 1, 2007 and March 31, 2011, unless the higher pipeline rates, subject to refund, were paid by the Utilities through an adjustment to the Annual Demand Cost Cap as described above, in which case the refunds will be returned to the Utilities. However, if a contingency occurs resulting in an

adjustment to increase the Utilities' costs for ratemaking purposes, such an increase will be reduced by future pipeline refunds.

Article IV

Entitlement Utilization

4.1 In order to obtain proceeds to offset gas sales customers' costs, while also providing non-discriminatory access to available capacity, the Utilities' available unused entitlements will be divided into equal halves, with 50% of anticipated unused entitlements, as determined by the Utilities' supply plans, retained by ProLiance, subject to the Profit Sharing Mechanism described in Sections 4.6 through 4.10 below. The 50% of the anticipated unused entitlements not retained by ProLiance will be offered for sale by the Utilities through a bidding process administered by Utility personnel, with clear separation from ProLiance's operations.

4.2 The Utilities' available entitlements will be determined from the total long haul transport entitlements separately for each pipeline based upon the delivery services provided by ProLiance to the Utilities, but including entitlements on Heartland Gas Pipeline and the upstream entitlements on Midwestern Gas Transmission pipeline to the extent it is associated with Heartland delivery entitlements and necessary for providing service to Citizens under the Heartland Appendix Service. Any of the anticipated unused entitlements not offered for sale by the Utilities pursuant to the process described in Sections 4.3 through 4.5 below will

be deemed retained entitlements, subject to the provisions of Sections 4.6 through 4.10 below.

4.3 With respect to the entitlements offered for sale by the Utilities, offers will be made in semi-annual seasonal releases, with any additional available entitlements being offered in monthly releases. In the Entitlement Auction administered by the Utilities, bid packages will not exceed 10,000 DTH per day.

4.4 In the event of recall, whether intraday or otherwise, the total quantity recalled will be divided between the Profit Sharing portion and the Entitlement Auction portion in approximately equal measure. Offering entitlements for sale subject to intraday recall may occur to the extent operationally necessary, but shall be limited to the extent possible to enhance the value of the entitlements. Recall provisions shall be designed to protect the reliability of system supply for the Utilities, while maximizing the value of the Utilities' entitlements. During the winter months, the entitlements sold with intraday recall terms will not exceed 75% of the available entitlements; during the shoulder months such entitlements will not exceed 50% of the available entitlements; and during the summer months such entitlements will not exceed 25% of the available entitlements.

4.5 The Utilities will offer the 50% of the anticipated unused entitlements not covered by the Profit Sharing Mechanism via a pre-

arranged sales process using an electronic bulletin board that will solicit bids. Monthly entitlements that are not sold via the pre-arranged process also will be offered via a non-discriminatory auction process. The pre-arranged sales process and auction process will be conducted in accordance with the guidelines attached as Appendix D. Those guidelines will be implemented and construed to promote the following goals: (1) competition; (2) nondiscriminatory open access; (3) the highest economic value consistent with reliable supply and fair competition; and (4) process transparency. The Utilities will retain 15% of the proceeds from this sales process to offset administrative costs.

4.6 Notwithstanding Section 4.9 below, for the period specified in Appendix G, April 1, 2006 until October 31, 2007, the Parties have agreed to the Value Sharing stated therein. Thereafter, the OUCC and ProLiance will specify by April 30, 2008 a new Shared Value Mechanism under the Settlement for the period from November 1, 2007 until the conclusion of the Settlement period. In the absence of agreement on the new Shared Value Mechanism, either may seek a determination of an appropriate Shared Value under 4.7, 4.8, 4.9, and 4.10 from the Commission by filing a petition no earlier than May 1, 2007 and no later than May 31, 2008.

4.7 The value of entitlements retained by ProLiance will be measured against the market area sale value using a benchmark formula as well as the most accurate data reasonably available to determine value. The benchmark includes an offset to reflect ProLiance's overhead. Guidelines applicable to the calculation of value are attached as Appendix G.

4.8 To determine annually whether the measurement of value continues to be appropriate and accurate, the OUCC will be given access to actual transaction (sales) confirmations for ProLiance related to industrial and commercial customers on pipelines that deliver to the Utilities to review the value received for those customers through both on and off system sales, as well as underlying cost projections used for pricing. With respect to a review of cost data, allocations, benchmarks and proxies may be needed to conduct a reasonable audit and understanding of cost data. In conducting the annual review, the OUCC and ProLiance will consider the timing of entry into industrial and commercial contracts, and may consider alternate point in time benchmarks where appropriate to correlate prevailing market values during the months where ProLiance has entered into the highest number of industrial and commercial contracts. The review will examine whether the formulaic approach has produced reasonable and accurate results to be used in the Profit Sharing Mechanism. If the formula is determined to be inappropriate or inaccurate, the parties will negotiate in good faith to

modify the Profit Sharing Mechanism in order to produce appropriate and accurate results.

4.9 The value of entitlements as determined by the benchmark formula shall be shared between ProLiance and the Utilities' customers at the rate of 75% to customers and 25% to ProLiance.

4.10 The scope of the entitlements covered by this Article will consist of all long haul transportation entitlements reserved to meet Utility sales demand and paid for by Utility ratepayers, and will include the entitlements currently subject to the auction procedures from the prior GCA50 Settlement as well as any intrastate pipeline capacity reserved on behalf of the Utilities subsequent to the GCA50 Settlement, although the entitlements could change, plus or minus, over time as services are renewed, dropped or added. None of the provisions in this Article will prevent the reduction of existing entitlements where that reduction is consistent with best cost reliable portfolio services. All entitlements within the scope of this Article will be either: (1) utilized to meet actual Utility demand; (2) marketed through the Entitlement Auction process; or (3) accounted for in the Profit Sharing Mechanism.

Article V

Affiliate Guidelines

5.1 Citizens and IGC/SIGECO will comply with the affiliate guidelines set forth in Appendices H and I, which are incorporated herein

by reference. The provision of services expressly provided for in the agreements set forth in Appendices A, B and C will not be considered a violation of the affiliate guidelines. With the exception of the contracts and related services expressly agreed to by the Parties in this Settlement, ProLiance is not otherwise exempt from the Affiliate Guidelines. The affiliate guidelines will remain in force unless and until modified, rescinded or superseded by order of the Commission.

5.2 No contractual arrangements with ProLiance, or its direct or indirect subsidiaries, will be negotiated on behalf of any of the Utilities by any Utility employee who is an officer or director of ProLiance.

5.3 The Parties agree to work together in good faith to interpret the provisions of the Settlement and the Affiliate Guidelines so that they will be implemented as intended. In furtherance of this agreement, the Parties and Signatory have provided for and encourage potential alternative methods to resolve disputes, as provided in the attached Appendix J.

Article VI

Customer Education

6.1 IGC, Citizens and SIGECO will conduct focused educational and publicity efforts directed both to customers and to potential competitors to explain the process for offering for sale the Utilities' available entitlements via the pre-arranged offering and the auction process. Within sixty (60) days after a Commission order approving the Settlement becomes final and non-appealable, the Utilities will host seminars and workshops for competitors and interested customers, explaining relevant provisions of the Settlement. The notice to customers eligible to purchase gas in the competitive market and all written materials associated with the seminars and workshops shall be prepared by the Utilities and provided to the Parties for review and approval prior to dissemination. The Utilities will coordinate with the OUCC and the I.G.C.G.-Industrial Group in preparing the presentations for the seminars and workshops.

6.2 Customer inquiries regarding gas supply providers will be handled in a competitively neutral manner consistent with the Affiliate Guidelines attached hereto.

Article VII

Joint Administration Benefits

7.1 Contingent on ProLiance's continued administration of gas supply for the Utilities, in 2006, \$2 million will be contributed to ratepayer programs that have been selected by the Utilities, after consultation with the OUCC. This contribution will continue each year ProLiance provides supply to the Utilities through 2010, with a pro rata payment made for 2011. The initial payment will be made within sixty (60) days following Commission approval of this Settlement, and all subsequent payments will be made by January 31 of the relevant year. Citizens' payment each year shall be calculated by multiplying \$2 million by Citizens By-Products' (or successor's) percentage share of ProLiance earnings for that year; Vectren's payment each year shall be calculated by multiplying \$2 million by Vectren Energy Solutions' (or successor's) percentage share of ProLiance earnings for that year. Each year, ten percent of the annual contribution will be allocated as a grant to the Indiana Utility Rate Payer Trust and the remaining ninety percent will be allocated to low-income programs.

Article VIII

Settlement Review

8.1 The Settlement Parties will meet no later than June 1, 2007, and again no later than June 1, 2009 to review the Entitlement Auction Process and the operation of the Profit Sharing Mechanism benchmarks.

By agreement of the signatories, adjustments may be made to improve such processes that are consistent with the overall agreement of the signatories through a process that remains subject to Commission oversight and approval.

Article IX

Audit and Consulting Costs

9.1 The signatories agree that to assure the proper effectuation of the Settlement, periodic review of the terms agreed to herein should occur. On a semi-annual basis, books, records and data reasonably related to the provisions of this Settlement may be formally reviewed by the OUCC. In the event the OUCC employs an outside auditor or consultant to assist in this review process, the Utilities will pay up to \$125,000 each year, which may be used to offset the OUCC's reasonable costs specifically incurred for such review. Citizens' payment each year shall be calculated by multiplying \$125,000 by Citizens By-Products' (or successor's) percentage share of ProLiance earnings for that year; Vectren's payment each year shall be calculated by multiplying \$125,000 by Vectren Energy Solutions' (or successor's) percentage share of ProLiance earnings for that year. Thirty days after Commission approval of this settlement, such funds will be placed in an account which may be drawn upon by the OUCC, subject to submission of appropriate invoices demonstrating incurrence of recoverable costs for audits related to the Settlement.

9.2 To the extent the OUCC's outside auditor or consultant expenses do not total \$125,000 in a given year, the OUCC may carry over the balance to fund reviews in the next year. The Utilities will fund the increment between any carried over balance and \$125,000 no later than January 31 each year for the duration of the settlement.

Article X

Duration of Supply Relationship

10.1 ProLiance will provide gas supply services consistent with the provisions set forth herein for a term beginning April 1, 2006 and ending March 31, 2011. Prior to April 30, 2010, the Parties will commence discussions regarding the terms for the Utilities' receipt of gas supply services after March 31, 2011. In the event the Parties fail to reach an agreement on terms for the provision of supply services after expiration of the Settlement, any or all of the Utilities may propose to purchase services from an affiliate, with any such proposal filed with the Commission by October 1, 2010. In the event of such a filing, the Petitioning Utility or Utilities will bear the burden of proof to demonstrate the proposed affiliate agreement is in the public interest.

10.2 Unless otherwise pre-approved by the Commission, each of the Utilities will maintain its respective commodity merchant function during the term of the Settlement.

10.3 It is contemplated that Vectren and Citizens By-Products will maintain their ownership control of ProLiance during the term of the Settlement. In the event either member proposes to transfer its ownership interest in ProLiance to another entity, such transfer would not take place absent prior discussion with the OUCC and the I.G.C.G. Industrial Group and potential review and negotiation of all terms and conditions contained in the Settlement.

Article XI

Enforcement and Remedies

11.1 Any of the Parties, individually or collectively, as well as individual non-parties, shall be entitled to seek enforcement of the Settlement's provisions, including the incorporated affiliate guidelines, against the Utilities. The Utilities also reserve the right to seek enforcement of the Settlement. All complaints related to compliance with the terms of the affiliate guidelines shall be initiated in accordance with the process set forth in the affiliate guidelines, specifically Appendix G at ¶18 and/or Appendix H at ¶18. All other complaints arising under the Settlement may be initiated in accordance with the process set forth in the affiliate guidelines, but in such instances completion of the informal review process will not be deemed a prerequisite to the commencement of enforcement proceedings before the Commission, provided that the applicable Utility is given at least three business days' prior written notice of any complaint.

11.2 Subject to Section 11.1, any of the Parties, individually or collectively, as well as individual non-parties, may raise Settlement compliance issues by filing a complaint with the Commission. However, with respect to complaints filed at the Commission, a non-party must file with any Settlement compliance-related complaint a verified statement supporting its position, must demonstrate that it has been adversely affected and has a "substantial and legitimate interest" in the compliance issue, and if such a non-party is found not to have a meritorious complaint, thereafter it will be prohibited from bringing or participating in complaints pursuant to the Settlement enforcement process, but still would have access to the statutory complaint process.

11.3 Upon its own motion or at the request of any Party or complainant, the Commission may notice and thereafter conduct a hearing to determine whether the Utilities, individually or collectively, have failed to perform any of the obligations under this Settlement. A failure of ProLiance to comply with provisions of this Settlement applicable to it shall constitute a failure of the applicable Utility or Utilities to perform an obligation under the Settlement. If, after notice and hearing, the Commission enters a final order determining that there has been a failure to perform an obligation imposed herein, the applicable Utility or Utilities shall commence corrective action or cause corrective action to be commenced within thirty (30) days or as directed by the Commission. Failure of the applicable Utility or Utilities to comply with a Commission

order entered under this Section within a reasonable period shall be subject to any additional enforcement and penalties under this Section as a separate violation of this Settlement.

11.4 In considering whether to impose a penalty or other remedy for non-compliance, the Commission shall consider the gravity of the violation or failure to comply, the good faith of the Utility or other Signatory in attempting to achieve compliance after notice of the violation or failure to comply, whether previous violations have occurred, and if so, the frequency and nature of such other violations, the effect of the penalty on the Utility's ability to provide adequate and reliable service, and other relevant factors. If a penalty is ordered by the Commission, it shall be paid to customers as a further reduction in the Utility's gas costs, or otherwise as directed by the Commission.

11.5 In the event the Commission finds a violation in an enforcement proceeding pursuant to Section 11.3 to be knowing and intentional, the Commission may require the violator to pay the reasonable fees, costs and expenses of the initiating party or parties. If the Commission finds that a frivolous complaint has been filed, the Commission may require the party that initiated the complaint to pay the applicable Utility's reasonable fees, costs and expenses of defending itself. A reasonable award shall be determined in light of the factors set forth in Section 11.4.

11.6 The Commission shall have the authority to impose penalties only to the extent necessary to assure compliance with the terms of the Settlement. Penalties, if any, are intended to be remedial and not punitive in nature, and should not be imposed for inadvertent or unintentional violations and when imposed the amount of any penalty should be proportionate to the significance of the violation. Any penalty amount shall reflect the factors set forth in Section 11.4

11.7 To the extent that any violation of the Settlement results in the consumer portion of economic benefits shared pursuant to Articles III, IV and VII being less than it would have been as a result of compliance, the Commission shall have the authority to order a Utility to share the benefits as required by the Settlement, both retroactively and prospectively. Such an order will not constitute a "penalty or other remedy" within the meaning of Sections 11.4 and 11.6.

11.8 If the Commission finds that a violation of the Settlement, which results in the consumer portion of economic benefits shared pursuant to Articles III, IV and VII being less than it would have been as a result of compliance, is both (a) intentional and (b) material, the Commission shall have the authority to order reduction or elimination on a prospective basis of the Utility share of the affected benefit(s). Such an order will constitute a "penalty or other remedy" within the meaning of Sections 11.4 and 11.6.

11.9 If a Utility commits multiple separate violations of the Settlement that the Commission finds are both intentional and material, such violations shall constitute "material and irreparable harm" to the Utility's customers within the meaning of I.C. § 8-1-2.5-7.

11.10 Nothing in the Settlement or any of its appendices shall be construed as restricting or qualifying remedies for conduct that violates independent standards or principles of law, and in connection with such remedies none of the enforcement procedures and remedies provided for herein should be construed as establishing any exhaustion requirements or other prerequisites to seeking such independent relief.

11.11 Counsel who have represented Signatories in connection with the negotiation of the Settlement acknowledge that, upon Commission approval, they would have a conflict with respect to any potential future representations that would involve a challenge to the validity and/or reasonableness of the terms and conditions of the Settlement, provided that all Signatories and counsel retain the right to seek enforcement of the Settlement and to pursue remedies for any violations of its provisions.

11.12 The Signatories, on behalf of themselves and their agents, counsel and privies, agree that the Settlement shall be subject to an obligation of good faith and fair dealing, and that no Signatory, directly or

indirectly, shall engage in conduct that would have the effect of depriving any other Signatory of the negotiated benefits.

Article XII

Alternative Regulatory Oversight

12.1 Those specific terms of this Settlement that are necessary to replace traditional regulation are limited in scope and application. Further, the alternative regulatory provisions are being pursued solely to effect the specified terms and mechanisms provided for under this Settlement and are limited in time and to the extent necessary to implement the terms of this Settlement. Nothing in this Settlement is intended to limit or prevent the Commission from fulfilling its statutory obligations and carrying out any mandates under any applicable law. The Commission shall retain all jurisdiction over the Utilities that is not expressly declined or supplanted by the express provisions of this Settlement. The Commission shall continue to oversee and regulate the Utilities' rates and charges, including those specified mechanisms and charges expressly created and/or modified by the provisions of this Settlement. The Commission further shall retain jurisdiction to the extent necessary to enforce the terms and conditions of this Settlement. The Commission shall, only to the extent necessary to effectuate the express and limited terms of this Settlement, expressly modify its jurisdiction and review under I.C. § 8-1-2-42(g), and any of the Commission's rules, standards, or other regulatory provisions based upon or related thereto.

12.2 At any time during the term of this Settlement, the Commission, upon its own motion and after notice and hearing, may conduct a review of the Utilities' compliance with the terms of this Settlement.

12.3 With regard to those areas to which the alternative regulatory provisions apply, the Commission shall not stay, suspend or otherwise alter the operation or effect of any term or provision of this Settlement without first providing notice and an opportunity for hearing in accordance with I.C. § 8-1-2.5-7.

Article XIII

Comprehensive Agreement Requirement and Effect of Change in Law

13.1 This Settlement is an integrated proposal in which each provision is dependent on others. It is a comprehensive agreement comprised of individual pieces designed to work together to benefit all stakeholders. As such, the proposal should be judged and approved in its entirety and without change unacceptable to any of the Signatories to this Settlement. The commitments made herein are conditioned upon overall approval of this entire Settlement.

13.2 Each Utility agrees that: (a) in the event there is a change in the statutory law, it will continue to be bound by and will fulfill its obligations under this Settlement, unless to do so would be unlawful; and (b) it will not propose, endorse or seek state legislation that, if enacted into

law, would make it unlawful for any Signatory to comply with those obligations through April 1, 2011, provided nothing in this provision shall be construed as abrogating the OUCC's statutory responsibilities. In the event there is a change in the law which would have the effect (either as a direct requirement or condition or through an optional form of regulation) of superseding, terminating or diminishing any Signatory's obligations under this Settlement, any such Signatory may take advantage of such change in the law effective April 1, 2011, and thereafter be governed under the changed law.

Article XIV

Procedure Before the Commission

14.1 All of the Parties shall support this Settlement before the Commission and request that the Commission accept and approve the Settlement without any change or condition(s) unacceptable to any Signatory. The Parties shall submit this Settlement and the supporting evidence conditionally and, if the Commission fails to approve the Settlement in its entirety without any changes or condition(s) unacceptable to any Signatory, the Settlement and the supporting evidence shall be withdrawn.

14.2 All evidence supporting the Settlement, as well as a proposed order approving the Settlement and any and all further documents as may be necessary and appropriate to secure Commission

approval, shall be reviewed and agreed upon by the Parties prior to filing. Provided the evidence is duly reviewed and approved, the Parties waive cross-examination of any witness offering evidence in support of the Settlement. Except as may be mutually agreed among the Parties, no other evidence may be offered by any Party.

14.3 The Parties will stipulate that the evidence in support of this Settlement constitutes substantial evidence that the Settlement is in the public interest and provides an adequate evidentiary basis upon which the Commission can make any findings of fact and conclusions of law necessary for the approval of the Settlement, as filed.

14.4 The Signatories shall not appeal or seek rehearing, reconsideration or a stay of any final order by the Commission approving the Settlement in its entirety without change or condition(s) unacceptable to any Signatory (or related orders to the extent such orders are specifically implementing the provisions of this Settlement) and shall support this Settlement in the event of any appeal or a request for rehearing, reconsideration or a stay by any person not a Signatory hereto.

Article XV

Effect and Use of Settlement

15.1 Neither the making of this Settlement nor any of its provisions shall constitute in any respect an admission by any Signatory in this or any other litigation or proceeding. Neither the making of this

Settlement (nor the execution of any of the other documents or pleadings required to effectuate the provisions of this Settlement), nor the provisions thereof, nor the entry by the Commission of a final order approving this Settlement, shall establish any principles or precedent applicable to Commission proceedings other than those resolved herein or to utilities other than the Parties hereto.

15.2 This Settlement shall not constitute nor be cited as precedent by any person or deemed an admission by any Signatory on these particular issues in any other proceeding before the Commission or in any court of competent jurisdiction, except if necessary to enforce its terms. This Settlement is solely the result of compromise in the settlement process and except as provided herein, is without prejudice to and shall not constitute a waiver of any position that any of the Signatories may take with respect to any or all of the items resolved here and in any future regulatory or other proceedings.

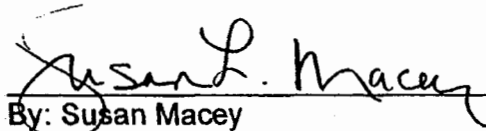
15.3 The communications and discussions during the negotiations and conferences which have produced this Settlement have been conducted on the explicit understanding that they are, or relate to, offers of settlement and shall be privileged and confidential, shall be without prejudice to the position of any Signatory, and are not to be used in any manner in connection with any other proceeding or otherwise.

15.4 The Signatories shall agree on the form, wording and timing of any public/media announcement of this Settlement and the terms thereof. All Signatories may respond individually without prior approval of the Signatories to questions from the public or media, provided that such responses are consistent with such announcement and do not disparage any of the Signatories.

15.5 The Signatories have represented and agreed that the individuals executing this Settlement are fully authorized to do so, on behalf of the Signatories who will be bound thereby.

ACCEPTED and AGREED this 1st day of February, 2006.

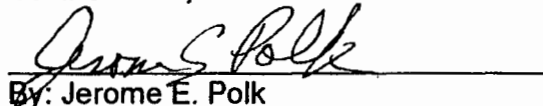
**INDIANA OFFICE OF UTILITY
CONSUMER COUNSELOR**


By: Susan Macey

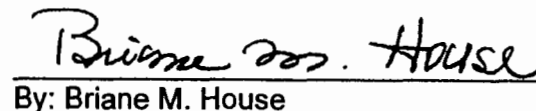
**BOARD OF DIRECTORS FOR
UTILITIES OF THE DEPARTMENT OF
PUBLIC UTILITIES OF THE CITY OF
INDIANAPOLIS, AS SUCCESSOR
TRUSTEE OF A PUBLIC CHARITABLE
TRUST, D/B/A CITIZENS GAS &
COKE UTILITY**


By: Michael B. Cracraft

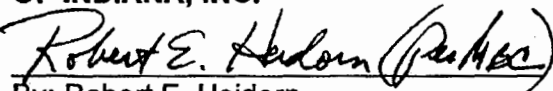
**CITIZENS ACTION COALITION
OF INDIANA, INC.**


By: Jerome E. Polk

PROLIANCE ENERGY, LLC


By: Briane M. House

**VECTREN ENERGY DELIVERY
OF INDIANA, INC.**


By: Robert E. Heidorn

I.G.C.G. – INDUSTRIAL GROUP


By: Todd A. Richardson

GAS SALES AND PORTFOLIO ADMINISTRATION AGREEMENT

This Gas Sales And Portfolio Administration Agreement ("Agreement") is entered into the ____ day of _____, 2006, for services to begin upon regulatory approval of this Agreement as referenced below, by and between the Board of Directors for Utilities of the Department of Public Utilities of the City of Indianapolis, d/b/a CITIZENS GAS & COKE UTILITY ("Buyer") and PROLIANCE ENERGY, LLC ("Seller") (collectively, the "Parties" or individually "Party"). Buyer and Seller agree as follows:

RECITALS

1. Seller is a limited liability company created and existing under the laws of the State of Indiana, with its registered office at 111 Monument Circle, Suite 2200, Indianapolis, Indiana.
2. Buyer is a municipal gas utility whose assets are subject to a public charitable trust existing under the laws of the State of Indiana with its principal place of business at 2020 North Meridian Street, Indianapolis, Indiana.
3. This Agreement contains the mutual promises and covenants pursuant to which Buyer as a purchaser of natural gas and portfolio administration services, and Seller as a merchant of natural gas and portfolio administration services, shall perform the transactions described herein.
4. Under this Agreement, Seller agrees to provide natural gas to Buyer consistent with the terms and conditions contained herein.
5. This Agreement contains terms that reflect the terms of a negotiated settlement agreement ("Settlement") entered into with non-parties to this Agreement. The Agreement, as part of the Settlement, will be reviewed by the Indiana Utility Regulatory Commission (the "Commission"), and will become effective on the first day of the month following issuance of a final order by the Commission in Cause No. 42973 finding that the Agreement is in the public interest.
6. This Agreement shall be subject to, and interpreted consistent with, the Settlement.

DEFINITIONS

The following terms shall have the following definitions for this Agreement and its Appendices:

1. The term "Balancing Quantities" shall mean the quantity of Gas which satisfies the difference between the Gas quantities scheduled for delivery to Buyer's Delivery Points and the actual physical flow of Gas taken by Buyer at the Delivery Points.
2. The term "Btu" shall mean British thermal unit, as defined in Transporter's Tariff
3. The term "Contract Month" shall mean a calendar month during the effectiveness of this Agreement.
4. The term "Contract Rates" shall apply to the demand costs as well as the variable costs associated with delivery service as described in Appendix C.
5. The term "Day" shall be defined as it is defined in Transporter's Tariff, or as applied by Transporter.
6. The term "Delivery Points" shall mean the points of delivery of Gas from Seller to Buyer as specified in Appendix A.
7. The term "FERC" shall mean the Federal Energy Regulatory Commission.
8. The term "Gas" shall mean natural gas.
9. The term "GCIM" shall mean the gas cost incentive mechanism provided for in the Settlement.
10. The term "Maximum Daily Quantities" or "MDQ" shall mean the maximum quantity of Gas which Seller shall be obligated to supply on a firm basis to Buyer's Delivery Points on a particular day.
11. The term "Maximum Portfolio Entitlement" shall mean the maximum deliverability that Buyer is entitled to under the Services identified on Appendix C.
12. The term "Maximum Seasonal Quantities" or "MSQ" shall mean the maximum quantity of Gas which Seller shall be obligated to supply on a firm basis to Buyer's Delivery Points in a Summer or Winter.
13. The terms "MMBtu", "Dekatherm" or "DTH" shall mean one million (1,000,000) BTUs.
14. The term "Nominated Daily Quantities" shall mean the quantity of Gas nominated on a particular day for delivery to Buyer's Delivery Points, including deliveries to storage for Buyer.
15. The term "PEPL" shall mean Panhandle Eastern Pipe Line Company.
16. The term "Portfolio Services" shall mean all of the Services that may be utilized to deliver Gas to Buyer, and which are identified on Appendix C.
17. The term "Summer" shall mean the summer season months of April through October, inclusive.

18. The term "Texas Gas" shall mean Texas Gas Transmission Corporation.
19. The term "Transporter" shall mean the transporting pipeline(s) interconnected with Buyer, including without limitation PEPL, TL, Texas Gas, or Heartland Gas as applicable to the transaction involved.
20. The term "Transporter's Tariff" shall mean the tariff provisions of Transporter, as approved by the FERC, or any successor thereto, and Buyer's or Seller's contractual arrangements with Transporter, including changes to such tariff and arrangements made after this Agreement is effective.
21. The term "TL" shall mean Trunkline Pipeline Company.
22. The term "Winter" shall mean the winter season months of November through March, inclusive.

ARTICLE 1- GAS SALES

1.1. Seller represents and warrants that Seller can and shall stand ready to provide on a firm basis for Buyer's purchase at Buyer's Delivery Points the daily and seasonal quantities of Gas set forth herein. Seller's firm supply delivery obligation will be limited, however, to the supplies Buyer previously ordered and Supplier subsequently reserved on behalf of Buyer in accordance with Seller's responsibilities under the contract. Additional Buyer requests for Seller to purchase supplies above reserved supplies will be performed by Seller on a reasonable best efforts basis. Seller's marketing activities will not be conducted in a manner that compromises the provision of reliable and firm service to Buyer.

1.2. During the term of this Agreement, unless Seller is unable to meet Buyer's Gas requirements, Buyer agrees that Seller shall be its supplier of Gas. However, Buyer shall have and maintain the right to produce, utilize, purchase or sell any and all Gas produced in Indiana which Buyer may be required to purchase under Ind. Code § 8-1-2-87.6 or any successor provision thereto of the Indiana Code.

1.3. The Maximum Daily Quantities, which Seller shall be obligated to provide on a firm basis at Buyer's Delivery Points, are specified in Appendix B.

1.4. The Maximum Seasonal Quantities during Winter or Summer, which Seller shall be obligated to provide on a firm basis at the Delivery Points, are specified in Appendix B.

1.5. Under this Agreement, Seller may fulfill its obligation to provide Gas to Buyer by using contracts entered into by and between Seller and third parties, including suppliers, pipelines and other service providers. Seller shall not be obligated to enter into commitments with suppliers, pipelines, or other service providers, which extend beyond the term or scope of this Agreement. If Seller, in order to serve Buyer, makes any commitments with suppliers, pipelines, or other service providers that extend beyond the end of the term of this Agreement, to the maximum extent permitted by law Buyer shall indemnify Seller for all expenses and costs associated with the continued service or cause the replacement Portfolio Administration Service provider to indemnify Seller for such costs.

1.6. If FERC should determine that Transporter's Tariff shall cease to apply, in whole or in part, to transactions hereunder, the Parties will promptly meet to determine and negotiate mutually acceptable replacement guidelines and standards. In that event, until an agreement is reached, the most recently effective Transporter's Tariff shall continue to apply for all purposes under this Agreement. Upon acceptance of the replacement guidelines and standards, Buyer and Seller agree to apply the replacement guidelines and standards retroactively to the cessation date of Transporter's Tariff. Any resolution shall be implemented within thirty (30) days of the acceptance of the replacement guidelines and standards.

1.7. Buyer shall be solely responsible for meeting the creditworthiness standards of any third party providing service under agreements entered into by Seller on Buyer's behalf.

ARTICLE 2- GAS SALES CHARGES

2.1 For all Maximum Portfolio Entitlements, Buyer shall pay Seller each Contract Month demand charges consistent with Section 3.4 of the Settlement, as well as variable costs (including without limitation all volumetric charges, GRI, fuel or other variable costs) incurred and associated with the services listed in Appendix C.

2.2 Buyer shall pay Seller each Contract Month the applicable supplier reservation costs specified in Appendix D.

2.3 For all commodity quantities, Buyer shall pay Seller each Contract Month those amounts for Gas priced in accordance with Appendix E of the Settlement ("GCIM agreement"), including volumes priced under the price volatility mitigation provisions thereof. All such purchases shall be reported on a monthly basis and shall include documentation necessary for review under the GCIM agreement and in Buyer's gas cost adjustment proceedings under Indiana Code Section 8-1-2-42 (g).

2.4 Buyer will pay any taxes which are imposed on or incurred by Seller due to this Agreement, or imposed on Buyer with respect to Gas delivered hereunder; provided, however, Buyer shall have no obligation to pay any sales or use taxes for which it delivers to Seller an appropriate exemption certificate.

2.5 All revenues Seller receives on Buyer's behalf as a result of auctioning unutilized pipeline entitlements consistent with the process set forth in Section 4.1 through 4.5 of the Settlement shall be reported in detail on a monthly basis to Buyer and shall be remitted to Buyer, net of reported expenses incurred by Seller in implementation of the auction.

ARTICLE 3- BALANCING

3.1 Seller shall provide Buyer with Balancing Quantities as part of its gas sales and portfolio administration services. Seller and Buyer shall be permitted reasonable balancing tolerances. Imbalances shall be made up in kind as agreed to by the Parties.

ARTICLE 4- PORTFOLIO ADMINISTRATION SERVICES

4.1 Seller's provision of portfolio administration services shall include without limitation Gas acquisition, scheduling receipt and delivery quantities with Gas suppliers and pipeline transporters, scheduling pipeline storage inventory quantities, providing delivered Gas supplies, supply planning assistance, posting and conducting the capacity auction on Transporters' EBBs, and periodic portfolio reporting. Buyer shall retain complete unilateral control of its physical Gas delivery, distribution, storage and transportation facilities.

4.2. The supply planning procedures set forth in Appendix F to the Settlement will be followed by the Parties in preparing and implementing supply plans.

4.3 Seller and Buyer shall review periodically Buyer's supply requirements and determine the need for potential adjustments to MDQ, MSQ and to delivery service requirements. All adjustments are subject to Seller and Buyer's prior approval.

4.4 During the term of this Agreement, Seller shall review all FERC regulatory filings that could reasonably be expected to impact the Gas supply or portfolio administration services provided by Seller to Buyer. Seller shall inform Buyer on a timely basis of Seller's review and analysis. Buyer shall timely communicate its interests to Seller. Seller shall provide for representation to protect the Parties' interest in FERC proceedings and related appeals and notify Buyer promptly concerning any conflict of interest it may identify. In the event Seller's interests conflict with those of Buyer, Buyer and Seller shall be free to represent their interests directly. Seller shall provide Buyer with periodic written reports on the status of such proceedings in which Seller represents Buyer.

4.5. In the event this Agreement is terminated for any reason, Buyer shall meet with Seller within five (5) days of notice of termination to reach agreement on the timely return of capacity rights to Buyer. During such a wind-up period, Seller shall continue to provide Buyer with necessary supply services and portfolio administration services to fully meet Buyer's MDQ and MSQ. During the wind up period, the terms and effectiveness of this Agreement shall remain in effect. The wind up period for purposes hereof, may extend up to eighteen (18) months. Unless terminated pursuant to Commission order under IC 8-1-2.5-7, the termination of this Agreement shall not relieve Buyer of its executory obligations under Article VII of the Settlement.

ARTICLE 5- TERM

5.1 Unless modified by 5.2 below, the term of this Agreement shall commence on the first day of the month following issuance of a final order in Cause No. 42973 and end on March 31, 2011. If for any reason this Agreement has not been extended after March 31, 2011, this Agreement shall continue on a month-to-month basis until arrangements are made by Buyer to acquire services by some other means.

5.2 Notwithstanding 5.1 above, this Agreement may be terminated prior to March 31, 2011 by either Party in the event of the failure by either Party to perform in any material respect any covenant or obligation set forth in this Agreement, and such failure is not excused by force majeure or cured within fifteen (15) business days after written notice thereof to the Party failing to perform; provided, however, if such failure is incapable of being cured within such fifteen (15) business day period and the Party failing to perform has commenced and is diligently pursuing a cure, such period shall be extended for such time as is reasonably necessary to cure such failure up to ninety (90) days.

5.3 This Agreement is conditioned on the continued solvency of Buyer and Seller. If one Party becomes insolvent or seeks bankruptcy relief, the other Party may prospectively terminate this Agreement upon prior written

notice without further obligation other than to pay for services or Gas previously provided. In such a circumstance, the Parties will implement wind-up provisions designed to continue reliable provision of service and delivery of Gas.

ARTICLE 6- CHANGES TO APPENDICES

- 6.1. The Parties agree to review Appendices attached to this Agreement annually and as necessary to make required adjustments to Buyer's supply services. Such changes shall be consistent with the Agreement terms. Such changes also will be consistent with Section 3.4 (2) of the Settlement, which provides for possible adjustments in delivery services for the periods April 1, 2007 through March 31, 2009, and April 1, 2009 through March 31, 2011. The annual, monthly, and daily deliverability of Buyer's Appendix Services will be designed to most effectively match Buyer's overall sendout requirements.
- 6.2. Prior to June 15th of each year Buyer shall submit to Seller peak day and annual demand data for both a normal and severe season plan in a monthly baseload and usage per degree day format. The foregoing information is critical to Seller's role of optimizing Buyer's portfolio and assisting in the determination of the most efficient set of Appendix Services for Buyer.

ARTICLE 7- OPERATIONS

- 7.1. Buyer and Seller agree to accept for purposes of this Agreement the applicable quality, delivery pressure, measurement and other applicable rules, procedures, guidelines, tariff provisions, contractual arrangements and policies of suppliers or Transporters, as the same may change from time to time.

ARTICLE 8- FORCE MAJEURE

- 8.1. All obligations of the Parties to this Agreement shall be suspended while and only for so long as compliance is prevented by a cause beyond the control of the Party claiming force majeure, such as an Act of God, war, civil disturbance, operational or performance failure or declaration of force majeure by a supplier, leased storage field operator, Transporter, or other service provider, operational flow order(s), federal or state or local law, or binding order of a court or governmental agency, provided the suspension shall be only to the extent performance was prevented by the event of force majeure. A Party claiming force majeure hereunder shall have the duty to make all reasonable efforts to remedy the force majeure condition as promptly as possible.

- 8.2. Notice of force majeure must be provided with reasonably full particulars to the other Party at or near the time the Party becomes aware of the force majeure. Notice shall be provided to the designated representatives for Buyer or Seller designated in Appendix F.

ARTICLE 9- TRANSPORTATION PENALTIES

9.1. Seller shall be liable for all imbalance or other penalties, cash-outs, or other costs imposed on Buyer or Seller by any third party, including without limitation Seller's upstream or other transporters and Transporters, to the extent that such penalties, cash-outs or other costs are caused by Seller's actions or inaction. Buyer shall be liable for all imbalance or other penalties, cash-outs, or other costs imposed on Buyer or Seller by any third parties, including without limitation Seller's upstream or other transporters and Transporters, to the extent that such penalties, cash-outs or other costs are caused by Buyer's actions or inaction.

ARTICLE 10- BILLING AND PAYMENT

10.1. Following each Contract Month, Seller shall furnish, or have furnished, an itemized statement to Buyer stating the amounts due Seller pursuant to this Agreement (the "Statement"). Following the receipt of Seller's Statement, Buyer shall make Payment by the due date. Invoice date, due date, and payment method shall be as specified in Appendix G.

10.2. Interest shall accrue on all late payments commencing on the applicable due date at the then current prime rate of J.P. Morgan, Chase Bank, or its successor, or the maximum lawful rate, whichever is lower.

ARTICLE 11- REMEDIES

11.1. If Seller fails to deliver scheduled Gas and such failure to deliver is not excused under Article 8 of this Agreement, then Seller shall reimburse Buyer for the amount of increased cost to Buyer of acquiring replacement Gas, as well as additional fees or penalties incurred as a result of such failure to deliver. The amount owed by Seller to Buyer hereunder shall be calculated as the product of (a) the difference, if positive, between the price paid for replacement Gas including any additional penalties, transportation, fuel and other variable costs incurred to receive such replacement Gas, and the then applicable commodity charge, and (b) the difference between the scheduled Gas and the quantity of Gas actually delivered by Seller. Buyer and Seller agree to act in good faith with respect to purchases of such replacement Gas so as to minimize Seller's obligations to Buyer under this Section.

11.2. If Buyer fails to receive scheduled Gas and such failure to receive is not excused under Article 8 of this Agreement, then Buyer shall reimburse Seller in an amount calculated as the product of (a) the difference, if positive, between the then applicable commodity charge and the price received from a third party purchaser, including any additional penalties, transportation, fuel and other variable costs incurred to deliver Gas to a third party purchaser, and (b) the difference between the scheduled Gas and the quantity of Gas actually received by Buyer. Seller and Buyer agree to cooperate in good faith so as to minimize Buyer's obligations to Seller under this Section.

11.3. Should the Commission impose enforcement penalties on Buyer which were caused by Seller's intentional non-compliance with the Settlement, Seller shall indemnify and hold harmless Buyer for such penalties, and any costs, fees, or expenses associated with defending such action.

ARTICLE 12- CORRESPONDENCE

12.1. Except as provided in Section 8.2, any notice, statement or bill shall be in writing and shall be duly delivered when (a) mailed, postage prepaid, by registered, certified, or first-class mail, or (b) sent by prepaid overnight delivery to the applicable address, or (c) sent by hand delivery, or (d) sent by facsimile directed to the appropriate person and facsimile number with hard copy also delivered as in (a), (b), or (c) above. Addresses, telephone numbers, and facsimile numbers are specified in Appendix F.

ARTICLE 13- MISCELLANEOUS

13.1. This Agreement is subject to all applicable laws, orders, rules, and regulations of any state or federal governmental body or official having jurisdiction and both Seller and Buyer agree that the transactions agreed to hereunder shall be conditioned upon compliance with all such laws, orders, rules and regulations.

13.2. Seller and Buyer expressly agree that laws of the State of Indiana shall govern the validity, construction, interpretation, and effect of this Agreement.

13.3. Either Party may pledge, mortgage, or assign its rights hereunder as security for indebtedness. This Agreement is otherwise non-assignable except with the prior written consent of Buyer and Seller.

13.4. Notwithstanding any other provisions herein, the Parties hereto waive any and all rights, claims, or causes of action arising under this Agreement for incidental, consequential or punitive damages. Buyer shall have the right to enforce any and all terms of this Agreement against Seller. To the extent performance of this Agreement by either Party conflicts with the Settlement, the Parties will take corrective action in order to ensure that performance is in accordance with the Settlement. The Parties acknowledge that a failure to take timely and appropriate corrective action may subject Buyer to compliance measures by third parties pursuant to Article VII of the Settlement.

13.5. The Parties acknowledge that their respective business records and information are confidential in nature and may contain proprietary and trade secret information. Notwithstanding the foregoing, Seller agrees to provide Buyer access to those records required to verify Seller's statements to Buyer. To the extent access to information is necessary consistent with the Settlement, appropriate protection of proprietary and trade secret information will be afforded.

13.6. No waiver by either Party of one or more defaults or breaches by the other in performance of any of the terms or provisions of this Agreement shall operate or be construed as a waiver of any future default or breach, whether of a like or of a different character.

13.7. The terms and conditions contained in this Agreement and its Appendices herein constitute the full and complete agreement between the Parties and any change to be made must be submitted in writing and executed by both Parties. The Parties acknowledge that this Agreement is effective and must be carried out and enforced in a manner consistent with the Settlement.

13.8. Each Party represents that it has all necessary power and authority to enter into and perform its obligations under this Agreement and that this Agreement constitutes a legal, valid and binding obligation of that Party enforceable against it in accordance with its terms, except as such enforceability may be affected by any bankruptcy law or the application of principles of equity.

13.9. In the event any of the terms, covenants or conditions of this Agreement, or any amendment hereto, or the application of any such terms, covenants or conditions shall be held invalid as to any Party or circumstance by any court having jurisdiction, all other terms, covenants, or conditions of this Agreement, or any amendment hereto, and their application, shall not be affected thereby and shall remain in full force and effect.

13.10. If any provision of this Agreement is declared or rendered unlawful by a court of law or regulatory authority with jurisdiction over either of the parties or deemed unlawful because of a statutory or other change in the law, or if either Party suffers a substantial economic detriment due either to a determination relating to this Agreement by such an authority, or as a result of fundamental changes in the marketplace or other substantial changes in existing circumstances, the Parties will promptly meet to determine and negotiate a mutually acceptable agreement on such replacement provisions necessary to maintain the benefits and obligations that arise under this Agreement.

IN WITNESS WHEREOF, the Parties hereto have executed this Agreement in duplicate originals.

"SELLER"
PROLIANCE ENERGY, LLC

By: _____
John R. Talley,
President

"BUYER"
CITIZENS GAS & COKE UTILITY

By: _____
Lindsay C. Lindgren
Vice President

Gas Sales And Portfolio Administration Agreement

APPENDICES INDEX

Appendices will be submitted to the Commission as a compliance filing following entry of an Order in Cause No. 42973.

Title	Appendix	Description
Buyer's Primary Delivery Points	A	List Primary Delivery Points on appropriate pipelines
Buyer's Maximum Quantities	B	Sets forth in Dth, by month and season, Buyer's Maximum Daily Quantities
Portfolio Information	C	Lists current Delivery Services
Supplier Reservation Costs	D	Lists Monthly and Seasonal Supplier Reservation Costs
Commodity Purchases-Gas Cost Incentive Mechanism	E	Incorporates the GCIM that is part of the Settlement Agreement
Notices	F	Addresses for purposes of notice to Seller and Buyer
Invoice/Payment Data	G	Sets invoice date and payment terms
Demand Cost Credit per Settlement	H	Sets Demand Cost Credit determined
Diversion of Entitlements	I	Entitlements diverted from and to Buyer
Portfolio Services	J	Specifics on portfolio services

GAS SALES AND PORTFOLIO ADMINISTRATION AGREEMENT

This Gas Sales And Portfolio Administration Agreement ("Agreement") is entered into the ____ day of _____, 2006, for services to begin upon regulatory approval of this Agreement as referenced below, by and between INDIANA GAS COMPANY, INC. ("Buyer") and PROLIANCE ENERGY, LLC ("Seller") (collectively, the "Parties" or individually "Party"). Buyer and Seller agree as follows:

RECITALS

1. Seller is a limited liability company created and existing under the laws of the State of Indiana, with its registered office at 111 Monument Circle, Suite 2200, Indianapolis, Indiana.
2. Buyer is a corporation created and existing under the laws of the State of Indiana with its principal place of business at Evansville, Indiana.
3. This Agreement contains the mutual promises and covenants pursuant to which Buyer as a purchaser of natural gas and portfolio administration services, and Seller as a merchant of natural gas and portfolio administration services, shall perform the transactions described herein.
4. Under this Agreement, Seller agrees to provide natural gas to Buyer consistent with the terms and conditions contained herein.
5. This Agreement contains terms that reflect the terms of a negotiated settlement agreement ("Settlement") entered into with non-parties to this Agreement. The Agreement, as part of the Settlement, will be reviewed by the Indiana Utility Regulatory Commission (the "Commission"), and will become effective on the first day of the month following issuance of a final order by the Commission in Cause No. 42973 finding that the Agreement is in the public interest.
6. This Agreement shall be subject to, and interpreted consistent with, the Settlement.

DEFINITIONS

The following terms shall have the following definitions for this Agreement and its Appendices:

1. The term "ANR" shall mean ANR Pipeline Company.

2. The term "Balancing Quantities" shall mean the quantity of Gas which satisfies the difference between the Gas quantities scheduled for delivery to Buyer's Delivery Points and the actual physical flow of Gas taken by Buyer at the Delivery Points.
3. The term "Btu" shall mean British thermal unit, as defined in Transporter's Tariff
4. The term "Contract Month" shall mean a calendar month during the effectiveness of this Agreement.
5. The term "Contract Rates" shall apply to the demand costs as well as the variable costs associated with delivery service as described in Appendix C.
6. The term "Day" shall be defined as it is defined in Transporter's Tariff, or as applied by Transporter.
7. The term "Delivery Points" shall mean the points of delivery of Gas from Seller to Buyer as specified in Appendix A.
8. The term "FERC" shall mean the Federal Energy Regulatory Commission.
9. The term "Gas" shall mean natural gas.
10. The term "GCIM" shall mean the gas cost incentive mechanism provided for in the Settlement.
11. The term "Maximum Daily Quantities" or "MDQ" shall mean the maximum quantity of Gas which Seller shall be obligated to supply on a firm basis to Buyer's Delivery Points on a particular day.
12. The term "Maximum Portfolio Entitlement" shall mean the maximum deliverability that Buyer is entitled to under the Services identified on Appendix C.
13. The term "Maximum Seasonal Quantities" or "MSQ" shall mean the maximum quantity of Gas which Seller shall be obligated to supply on a firm basis to Buyer's Delivery Points in a Summer or Winter.
14. The terms "MMBtu", "Dekatherm" or "DTH" shall mean one million (1,000,000) BTUs.
15. The term "Nominated Daily Quantities" shall mean the quantity of Gas nominated on a particular day for delivery to Buyer's Delivery Points, including deliveries to storage for Buyer.
16. The term "PEPL" shall mean Panhandle Eastern Pipe Line Company.
17. The term "Portfolio Services" shall mean all of the Services that may be utilized to deliver Gas to Buyer, and which are identified on Appendix C.

18. The term "Summer" shall mean the summer season months of April through October, inclusive.
19. The term "TETCO" shall mean Texas Eastern Transmission Corporation.
20. The term "Texas Gas" shall mean Texas Gas Transmission Corporation.
21. The term "Transporter" shall mean the transporting pipeline(s) interconnected with Buyer, including without limitation PEPL, TL, Texas Gas, or Heartland Gas as applicable to the transaction involved.
22. The term "Transporter's Tariff" shall mean the tariff provisions of Transporter, as approved by the FERC, or any successor thereto, and Buyer's or Seller's contractual arrangements with Transporter, including changes to such tariff and arrangements made after this Agreement is effective.
23. The term "TL" shall mean Trunkline Pipeline Company.
24. The term "Winter" shall mean the winter season months of November through March, inclusive.

ARTICLE 1- GAS SALES

1.1. Seller represents and warrants that Seller can and shall stand ready to provide on a firm basis for Buyer's purchase at Buyer's Delivery Points the daily and seasonal quantities of Gas set forth herein. Seller's firm supply delivery obligation will be limited, however, to the supplies Buyer previously ordered and Supplier subsequently reserved on behalf of Buyer in accordance with Seller's responsibilities under the contract. Additional Buyer requests for Seller to purchase supplies above reserved supplies will be performed by Seller on a reasonable best efforts basis. Seller's marketing activities will not be conducted in a manner that compromises the provision of reliable and firm service to Buyer.

1.2. During the term of this Agreement, unless Seller is unable to meet Buyer's Gas requirements, Buyer agrees that Seller shall be its supplier of Gas. However, Buyer shall have and maintain the right to produce, utilize, purchase or sell any and all Gas produced in Indiana which Buyer may be required to purchase under Ind. Code § 8-1-2-87.6 or any successor provision thereto of the Indiana Code.

1.3. The Maximum Daily Quantities, which Seller shall be obligated to provide on a firm basis at Buyer's Delivery Points, are specified in Appendix B.

1.4. The Maximum Seasonal Quantities during Winter or Summer, which Seller shall be obligated to provide on a firm basis at the Delivery Points, are specified in Appendix B.

1.5. Under this Agreement, Seller may fulfill its obligation to provide Gas to Buyer by using contracts entered into by and between Seller and third parties, including suppliers, pipelines and other service providers. Seller shall not be obligated to enter into commitments with suppliers, pipelines, or other service providers, which extend beyond the term or scope of this Agreement. If Seller, in order to serve Buyer, makes any commitments with suppliers, pipelines, or other service providers that extend beyond the end of the term of this Agreement, to the maximum extent permitted by law Buyer shall indemnify Seller for all expenses and costs associated with the continued service or cause the replacement Portfolio Administration Service provider to indemnify Seller for such costs.

1.6. If FERC should determine that Transporter's Tariff shall cease to apply, in whole or in part, to transactions hereunder, the Parties will promptly meet to determine and negotiate mutually acceptable replacement guidelines and standards. In that event, until an agreement is reached, the most recently effective Transporter's Tariff shall continue to apply for all purposes under this Agreement. Upon acceptance of the replacement guidelines and standards, Buyer and Seller agree to apply the replacement guidelines and standards retroactively to the cessation date of Transporter's Tariff. Any resolution shall be implemented within thirty (30) days of the acceptance of the replacement guidelines and standards.

1.7 Buyer shall be solely responsible for meeting the creditworthiness standards of any third party providing service under agreements entered into by Seller on Buyer's behalf.

ARTICLE 2- GAS SALES CHARGES

2.1 For all Maximum Portfolio Entitlements, Buyer shall pay Seller each Contract Month demand charges consistent with Section 3.4 of the Settlement, as well as variable costs (including without limitation all volumetric charges, GRI, fuel or other variable costs) incurred and associated with the services listed in Appendix C.

2.2 Buyer shall pay Seller each Contract Month the applicable supplier reservation costs specified in Appendix D.

2.3 For all commodity quantities, Buyer shall pay Seller each Contract Month those amounts for Gas priced in accordance with Appendix E of the Settlement ("GCIM agreement"), including volumes priced under the price volatility mitigation provisions thereof. All such purchases shall be reported on a monthly basis and shall include documentation necessary for review under the GCIM agreement and in Buyer's gas cost adjustment proceedings under Indiana Code Section 8-1-2-42 (g).

2.4 Buyer will pay any taxes which are imposed on or incurred by Seller due to this Agreement, or imposed on Buyer with respect to Gas delivered hereunder; provided, however, Buyer shall have no obligation to pay any sales or use taxes for which it delivers to Seller an appropriate exemption certificate.

2.5 All revenues Seller receives on Buyer's behalf as a result of auctioning unutilized pipeline entitlements consistent with the process set forth in Section 4.1 through 4.5 of the Settlement shall be reported in detail on a monthly basis to Buyer and shall be remitted to Buyer, net of reported expenses incurred by Seller in implementation of the auction.

ARTICLE 3- BALANCING

3.1 Seller shall provide Buyer with Balancing Quantities as part of its gas sales and portfolio administration services. Seller and Buyer shall be permitted reasonable balancing tolerances. Imbalances shall be made up in kind as agreed to by the Parties.

ARTICLE 4- PORTFOLIO ADMINISTRATION SERVICES

4.1 Seller's provision of portfolio administration services shall include without limitation Gas acquisition, scheduling receipt and delivery quantities with Gas suppliers and pipeline transporters, scheduling pipeline storage inventory quantities, providing delivered Gas supplies, supply planning assistance, posting and conducting the capacity

auction on Transporters' EBBs, and periodic portfolio reporting. Buyer shall retain complete unilateral control of its physical Gas delivery, distribution, storage and transportation facilities.

4.2. The supply planning procedures set forth in Appendix F to the Settlement will be followed by the Parties in preparing and implementing supply plans.

4.3 Seller and Buyer shall review periodically Buyer's supply requirements and determine the need for potential adjustments to MDQ, MSQ and to delivery service requirements. All adjustments are subject to Seller and Buyer's prior approval.

4.4 During the term of this Agreement, Seller shall review all FERC regulatory filings that could reasonably be expected to impact the Gas supply or portfolio administration services provided by Seller to Buyer. Seller shall inform Buyer on a timely basis of Seller's review and analysis. Buyer shall timely communicate its interests to Seller. Seller shall provide for representation to protect the Parties' interest in FERC proceedings and related appeals and notify Buyer promptly concerning any conflict of interest it may identify. In the event Seller's interests conflict with those of Buyer, Buyer and Seller shall be free to represent their interests directly. Seller shall provide Buyer with periodic written reports on the status of such proceedings in which Seller represents Buyer.

4.5. In the event this Agreement is terminated for any reason, Buyer shall meet with Seller within five (5) days of notice of termination to reach agreement on the timely return of capacity rights to Buyer. During such a wind-up period, Seller shall continue to provide Buyer with necessary supply services and portfolio administration services to fully meet Buyer's MDQ and MSQ. During the wind up period, the terms and effectiveness of this Agreement shall remain in effect. The wind up period for purposes hereof, may extend up to eighteen (18) months. Unless terminated pursuant to Commission order under IC 8-1-2.5-7, the termination of this Agreement shall not relieve Buyer of its executory obligations under Article VII of the Settlement.

ARTICLE 5- TERM

5.1 Unless modified by 5.2 below, the term of this Agreement shall commence on the first day of the month following issuance of a final order in Cause No. 42973 and end on March 31, 2011. If for any reason this or a successor Agreement is not in effect after March 31, 2011, this Agreement shall continue on a month-to-month basis until arrangements are made by Buyer to acquire services by some other means.

5.2 Notwithstanding 5.1 above, this Agreement may be terminated prior to March 31, 2011 by either Party in the event of the failure by either Party to perform in any material respect any covenant or obligation set forth in this Agreement, and such failure is not excused by force majeure or cured within fifteen (15) business days after written notice thereof to the Party failing to perform; provided, however, if such failure is incapable of being cured within such fifteen (15) business day period and the Party failing to perform has commenced and is diligently pursuing a cure, such period shall be extended for such time as is reasonably necessary to cure such failure up to ninety (90) days.

5.3 This Agreement is conditioned on the continued solvency of Buyer and Seller. If one Party becomes insolvent or seeks bankruptcy relief, the other Party may prospectively terminate this Agreement upon prior written notice without further obligation other than to pay for services or Gas previously provided. In such a circumstance, the Parties will implement wind-up provisions designed to continue reliable provision of service and delivery of Gas.

ARTICLE 6- CHANGES TO APPENDICES

- 6.1. The Parties agree to review Appendices attached to this Agreement annually and as necessary to make required adjustments to Buyer's supply services. Such changes shall be consistent with the Agreement terms. Such changes also will be consistent with Section 3.4 (2) of the Settlement, which provides for possible adjustments in delivery services for the periods April 1, 2007 through March 31, 2009, and April 1, 2009 through March 31, 2011. The annual, monthly, and daily deliverability of Buyer's Appendix Services will be designed to most effectively match Buyer's overall sendout requirements.
- 6.2. Prior to June 15th of each year Buyer shall submit to Seller peak day and annual demand data for both a normal and severe season plan in a monthly baseload and usage per degree day format. The foregoing information is critical to Seller's role of optimizing Buyer's portfolio and assisting in the determination of the most efficient set of Appendix Services for Buyer.

ARTICLE 7- OPERATIONS

7.1. Buyer and Seller agree to accept for purposes of this Agreement the applicable quality, delivery pressure, measurement and other applicable rules, procedures, guidelines, tariff provisions, contractual arrangements and policies of suppliers or Transporters, as the same may change from time to time.

ARTICLE 8- FORCE MAJEURE

8.1. All obligations of the Parties to this Agreement shall be suspended while and only for so long as compliance is prevented by a cause beyond the control of the Party claiming force majeure, such as an Act of God, war, civil disturbance, operational or performance failure or declaration of force majeure by a supplier, leased storage field operator, Transporter, or other service provider, operational flow order(s), federal or state or local law, or binding order of a court or governmental agency, provided the suspension shall be only to the extent performance was prevented by the event of force majeure. A Party claiming force majeure hereunder shall have the duty to make all reasonable efforts to remedy the force majeure condition as promptly as possible.

8.2. Notice of force majeure must be provided with reasonably full particulars to the other Party at or near the time the Party becomes aware of the force majeure. Notice shall be provided to the designated representatives for Buyer or Seller designated in Appendix F.

ARTICLE 9- TRANSPORTATION PENALTIES

9.1. Seller shall be liable for all imbalance or other penalties, cash-outs, or other costs imposed on Buyer or Seller by any third party, including without limitation Seller's upstream or other transporters and Transporters, to the extent that such penalties, cash-outs or other costs are caused by Seller's actions or inaction. Buyer shall be liable for all imbalance or other penalties, cash-outs, or other costs imposed on Buyer or Seller by any third parties, including without limitation Seller's upstream or other transporters and Transporters, to the extent that such penalties, cash-outs or other costs are caused by Buyer's actions or inaction.

ARTICLE 10- BILLING AND PAYMENT

10.1. Following each Contract Month, Seller shall furnish, or have furnished, an itemized statement to Buyer stating the amounts due Seller pursuant to this Agreement (the "Statement"). Following the receipt of Seller's Statement, Buyer shall make Payment by the due date. Invoice date, due date, and payment method shall be as specified in Appendix G.

10.2. Interest shall accrue on all late payments commencing on the applicable due date at the then current prime rate of J.P. Morgan, Chase Bank, or its successor, or the maximum lawful rate, whichever is lower.

ARTICLE 11- REMEDIES

11.1. If Seller fails to deliver scheduled Gas and such failure to deliver is not excused under Article 8 of this Agreement, then Seller shall reimburse Buyer for the amount of increased cost to Buyer of acquiring replacement Gas, as well as additional fees or penalties incurred as a result of such failure to deliver. The amount owed by Seller to Buyer hereunder shall be calculated as the product of (a) the difference, if positive, between the price paid for replacement Gas including any additional penalties, transportation, fuel and other variable costs incurred to receive such replacement Gas, and the then applicable commodity charge, and (b) the difference between the scheduled Gas and the quantity of Gas actually delivered by Seller. Buyer and Seller agree to act in good faith with respect to purchases of such replacement Gas so as to minimize Seller's obligations to Buyer under this Section.

11.2. If Buyer fails to receive scheduled Gas and such failure to receive is not excused under Article 8 of this Agreement, then Buyer shall reimburse Seller in an amount calculated as the product of (a) the difference, if positive, between the then applicable commodity charge and the price received from a third party purchaser, including any additional penalties, transportation, fuel and other variable costs incurred to deliver Gas to a third party purchaser,

and (b) the difference between the scheduled Gas and the quantity of Gas actually received by Buyer. Seller and Buyer agree to cooperate in good faith so as to minimize Buyer's obligations to Seller under this Section.

11.3. Should the Commission impose enforcement penalties on Buyer which were caused by Seller's intentional non-compliance with the Settlement, Seller shall indemnify and hold harmless Buyer for such penalties, and any costs, fees, or expenses associated with defending such action.

ARTICLE 12- CORRESPONDENCE

12.1. Except as provided in Section 8.2, any notice, statement or bill shall be in writing and shall be duly delivered when (a) mailed, postage prepaid, by registered, certified, or first-class mail, or (b) sent by prepaid overnight delivery to the applicable address, or (c) sent by hand delivery, or (d) sent by facsimile directed to the appropriate person and facsimile number with hard copy also delivered as in (a), (b), or (c) above. Addresses, telephone numbers, and facsimile numbers are specified in Appendix F.

ARTICLE 13- MISCELLANEOUS

13.1. This Agreement is subject to all applicable laws, orders, rules, and regulations of any state or federal governmental body or official having jurisdiction and both Seller and Buyer agree that the transactions agreed to hereunder shall be conditioned upon compliance with all such laws, orders, rules and regulations.

13.2. Seller and Buyer expressly agree that laws of the State of Indiana shall govern the validity, construction, interpretation, and effect of this Agreement.

13.3. Either Party may pledge, mortgage, or assign its rights hereunder as security for indebtedness. This Agreement is otherwise non-assignable except with the prior written consent of Buyer and Seller.

13.4. Notwithstanding any other provisions herein, the Parties hereto waive any and all rights, claims, or causes of action arising under this Agreement for incidental, consequential or punitive damages. Buyer shall have the right to enforce any and all terms of this Agreement against Seller. To the extent performance of this Agreement by either Party conflicts with the Settlement, the Parties will take corrective action in order to ensure that performance is in accordance with the Settlement. The Parties acknowledge that a failure to take timely and appropriate corrective action may subject Buyer to compliance measures by third parties pursuant to Article VII of the Settlement.

13.5. The Parties acknowledge that their respective business records and information are confidential in nature and may contain proprietary and trade secret information. Notwithstanding the foregoing, Seller agrees to provide Buyer access to those records required to verify Seller's statements to Buyer. To the extent access to

information is necessary consistent with the Settlement, appropriate protection of proprietary and trade secret information will be afforded.

13.6. No waiver by either Party of one or more defaults or breaches by the other in performance of any of the terms or provisions of this Agreement shall operate or be construed as a waiver of any future default or breach, whether of a like or of a different character.

13.7. The terms and conditions contained in this Agreement and its Appendices herein constitute the full and complete agreement between the Parties and any change to be made must be submitted in writing and executed by both Parties. The Parties acknowledge that this Agreement is effective and must be carried out and enforced in a manner consistent with the Settlement.

13.8. Each Party represents that it has all necessary power and authority to enter into and perform its obligations under this Agreement and that this Agreement constitutes a legal, valid and binding obligation of that Party enforceable against it in accordance with its terms, except as such enforceability may be affected by any bankruptcy law or the application of principles of equity.

13.9. In the event any of the terms, covenants or conditions of this Agreement, or any amendment hereto, or the application of any such terms, covenants or conditions shall be held invalid as to any Party or circumstance by any court having jurisdiction, all other terms, covenants, or conditions of this Agreement, or any amendment hereto, and their application, shall not be affected thereby and shall remain in full force and effect.

13.10. If any provision of this Agreement is declared or rendered unlawful by a court of law or regulatory authority with jurisdiction over either of the parties or deemed unlawful because of a statutory or other change in the law, or if either Party suffers a substantial economic detriment due either to a determination relating to this Agreement by such an authority, or as a result of fundamental changes in the marketplace or other substantial changes in existing circumstances, the Parties will promptly meet to determine and negotiate a mutually acceptable agreement on such replacement provisions necessary to maintain the benefits and obligations that arise under this Agreement.

IN WITNESS WHEREOF, the Parties hereto have executed this Agreement in duplicate originals.

"SELLER"
PROLIANCE ENERGY, LLC

By: _____
John R. Talley,
President

"BUYER"
INDIANA GAS COMPANY, INC.

By: _____

Its: _____

Gas Sales And Portfolio Administration Agreement

APPENDICES INDEX

Appendices will be submitted to the Commission as a compliance filing following entry of an Order in Cause No. 42973.

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Portfolio Services	J	Specifics on portfolio services

GAS SALES AND PORTFOLIO ADMINISTRATION AGREEMENT

This Gas Sales And Portfolio Administration Agreement ("Agreement") is entered into the ____ day of _____, 2006, for services to begin upon regulatory approval of this Agreement as referenced below, by and between SOUTHERN INDIANA GAS AND ELECTRIC COMPANY, INC. ("Buyer") and PROLIANCE ENERGY, LLC ("Seller") (collectively, the "Parties" or individually "Party"). Buyer and Seller agree as follows:

RECITALS

1. Seller is a limited liability company created and existing under the laws of the State of Indiana, with its registered office at 111 Monument Circle, Suite 2200, Indianapolis, Indiana.
2. Buyer is a corporation created and existing under the laws of the State of Indiana with its principal place of business at Evansville, Indiana.
3. This Agreement contains the mutual promises and covenants pursuant to which Buyer as a purchaser of natural gas and portfolio administration services, and Seller as a merchant of natural gas and portfolio administration services, shall perform the transactions described herein.
4. Under this Agreement, Seller agrees to provide natural gas to Buyer consistent with the terms and conditions contained herein.
5. This Agreement contains terms that reflect the terms of a negotiated settlement agreement ("Settlement") entered into with non-parties to this Agreement. The Agreement, as part of the Settlement, will be reviewed by the Indiana Utility Regulatory Commission (the "Commission"), and will become effective on the first day of the month following issuance of a final order by the Commission in Cause No. 42973 finding that the Agreement is in the public interest.
6. This Agreement shall be subject to, and interpreted consistent with, the Settlement.

DEFINITIONS

The following terms shall have the following definitions for this Agreement and its Appendices:

1. The term "Balancing Quantities" shall mean the quantity of Gas which satisfies the difference between the Gas quantities scheduled for delivery to Buyer's Delivery Points and the actual physical flow of Gas taken by Buyer at the Delivery Points.

2. The term "Btu" shall mean British thermal unit, as defined in Transporter's Tariff
3. The term "Contract Month" shall mean a calendar month during the effectiveness of this Agreement.
4. The term "Contract Rates" shall apply to the demand costs as well as the variable costs associated with delivery service as described in Appendix C.
5. The term "Day" shall be defined as it is defined in Transporter's Tariff, or as applied by Transporter.
6. The term "Delivery Points" shall mean the points of delivery of Gas from Seller to Buyer as specified in Appendix A.
7. The term "FERC" shall mean the Federal Energy Regulatory Commission.
8. The term "Gas" shall mean natural gas.
9. The term "GCIM" shall mean the gas cost incentive mechanism provided for in the Settlement.
10. The term "Maximum Daily Quantities" or "MDQ" shall mean the maximum quantity of Gas which Seller shall be obligated to supply on a firm basis to Buyer's Delivery Points on a particular day.
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13. The term "MGT" shall mean Midwestern Gas Transmission Company.
14. The terms "MMBtu", "Dekatherm" or "DTH" shall mean one million (1,000,000) BTUs.
15. The term "Nominated Daily Quantities" shall mean the quantity of Gas nominated on a particular day for delivery to Buyer's Delivery Points, including deliveries to storage for Buyer.
16. The term "PEPL" shall mean Panhandle Eastern Pipe Line Company.
17. The term "Portfolio Services" shall mean all of the Services that may be utilized to deliver Gas to Buyer, and which are identified on Appendix C.
18. The term "Summer" shall mean the summer season months of April through October, inclusive.
19. The term "Texas Gas" shall mean Texas Gas Transmission Corporation.

20. The term "Transporter" shall mean the transporting pipeline(s) interconnected with Buyer, including without limitation PEPL, TL, Texas Gas, or Heartland Gas as applicable to the transaction involved.
21. The term "Transporter's Tariff" shall mean the tariff provisions of Transporter, as approved by the FERC, or any successor thereto, and Buyer's or Seller's contractual arrangements with Transporter, including changes to such tariff and arrangements made after this Agreement is effective.
22. The term "TL" shall mean Trunkline Pipeline Company.
23. The term "Winter" shall mean the winter season months of November through March, inclusive.

ARTICLE 1- GAS SALES

1.1. Seller represents and warrants that Seller can and shall stand ready to provide on a firm basis for Buyer's purchase at Buyer's Delivery Points the daily and seasonal quantities of Gas set forth herein. Seller's firm supply delivery obligation will be limited, however, to the supplies Buyer previously ordered and Supplier subsequently reserved on behalf of Buyer in accordance with Seller's responsibilities under the contract. Additional Buyer requests for Seller to purchase supplies above reserved supplies will be performed by Seller on a reasonable best efforts basis. Seller's marketing activities will not be conducted in a manner that compromises the provision of reliable and firm service to Buyer.

1.2. During the term of this Agreement, unless Seller is unable to meet Buyer's Gas requirements, Buyer agrees that Seller shall be its supplier of Gas. However, Buyer shall have and maintain the right to produce, utilize, purchase or sell any and all Gas produced in Indiana which Buyer may be required to purchase under Ind. Code § 8-1-2-87.6 or any successor provision thereto of the Indiana Code.

1.3. The Maximum Daily Quantities, which Seller shall be obligated to provide on a firm basis at Buyer's Delivery Points, are specified in Appendix B.

1.4. The Maximum Seasonal Quantities during Winter or Summer, which Seller shall be obligated to provide on a firm basis at the Delivery Points, are specified in Appendix B.

1.5. Under this Agreement, Seller may fulfill its obligation to provide Gas to Buyer by using contracts entered into by and between Seller and third parties, including suppliers, pipelines and other service providers. Seller shall not be obligated to enter into commitments with suppliers, pipelines, or other service providers, which extend beyond the term or scope of this Agreement. If Seller, in order to serve Buyer, makes any commitments with suppliers, pipelines, or other service providers that extend beyond the end of the term of this Agreement, to the maximum extent permitted by law Buyer shall indemnify Seller for all expenses and costs associated with the continued service or cause the replacement Portfolio Administration Service provider to indemnify Seller for such costs.

1.6. If FERC should determine that Transporter's Tariff shall cease to apply, in whole or in part, to transactions hereunder, the Parties will promptly meet to determine and negotiate mutually acceptable replacement guidelines and standards. In that event, until an agreement is reached, the most recently effective Transporter's Tariff shall continue to apply for all purposes under this Agreement. Upon acceptance of the replacement guidelines and standards, Buyer and Seller agree to apply the replacement guidelines and standards retroactively to the cessation date of Transporter's Tariff. Any resolution shall be implemented within thirty (30) days of the acceptance of the replacement guidelines and standards.

1.7. Buyer shall be solely responsible for meeting the creditworthiness standards of any third party providing service under agreements entered into by Seller on Buyer's behalf.

ARTICLE 2- GAS SALES CHARGES

2.1 For all Maximum Portfolio Entitlements, Buyer shall pay Seller each Contract Month demand charges consistent with Section 3.4 of the Settlement, as well as variable costs (including without limitation all volumetric charges, GRI, fuel or other variable costs) incurred and associated with the services listed in Appendix C.

2.2 Buyer shall pay Seller each Contract Month the applicable supplier reservation costs specified in Appendix D.

2.3 For all commodity quantities, Buyer shall pay Seller each Contract Month those amounts for Gas priced in accordance with Appendix E of the Settlement ("GCIM agreement"), including volumes priced under the price volatility mitigation provisions thereof. All such purchases shall be reported on a monthly basis and shall include documentation necessary for review under the GCIM agreement and in Buyer's gas cost adjustment proceedings under Indiana Code Section 8-1-2-42 (g).

2.4 Buyer will pay any taxes which are imposed on or incurred by Seller due to this Agreement, or imposed on Buyer with respect to Gas delivered hereunder; provided, however, Buyer shall have no obligation to pay any sales or use taxes for which it delivers to Seller an appropriate exemption certificate.

2.5 All revenues Seller receives on Buyer's behalf as a result of auctioning unutilized pipeline entitlements consistent with the process set forth in Section 4.1 through 4.5 of the Settlement shall be reported in detail on a monthly basis to Buyer and shall be remitted to Buyer, net of reported expenses incurred by Seller in implementation of the auction.

ARTICLE 3- BALANCING

3.1 Seller shall provide Buyer with Balancing Quantities as part of its gas sales and portfolio administration services. Seller and Buyer shall be permitted reasonable balancing tolerances. Imbalances shall be made up in kind as agreed to by the Parties.

ARTICLE 4- PORTFOLIO ADMINISTRATION SERVICES

4.1 Seller's provision of portfolio administration services shall include without limitation Gas acquisition, scheduling receipt and delivery quantities with Gas suppliers and pipeline transporters, scheduling pipeline storage inventory quantities, providing delivered Gas supplies, supply planning assistance, posting and conducting the capacity auction on Transporters' EBBs, and periodic portfolio reporting. Buyer shall retain complete unilateral control of its physical Gas delivery, distribution, storage and transportation facilities.

4.2. The supply planning procedures set forth in Appendix F to the Settlement will be followed by the Parties in preparing and implementing supply plans.

4.3 Seller and Buyer shall review periodically Buyer's supply requirements and determine the need for potential adjustments to MDQ, MSQ and to delivery service requirements. All adjustments are subject to Seller and Buyer's prior approval.

4.4 During the term of this Agreement, Seller shall review all FERC regulatory filings that could reasonably be expected to impact the Gas supply or portfolio administration services provided by Seller to Buyer. Seller shall inform Buyer on a timely basis of Seller's review and analysis. Buyer shall timely communicate its interests to Seller. Seller shall provide for representation to protect the Parties' interest in FERC proceedings and related appeals and notify Buyer promptly concerning any conflict of interest it may identify. In the event Seller's interests conflict with those of Buyer, Buyer and Seller shall be free to represent their interests directly. Seller shall provide Buyer with periodic written reports on the status of such proceedings in which Seller represents Buyer.

4.5. In the event this Agreement is terminated for any reason, Buyer shall meet with Seller within five (5) days of notice of termination to reach agreement on the timely return of capacity rights to Buyer. During such a wind-up period, Seller shall continue to provide Buyer with necessary supply services and portfolio administration services to fully meet Buyer's MDQ and MSQ. During the wind up period, the terms and effectiveness of this Agreement shall remain in effect. The wind up period for purposes hereof, may extend up to eighteen (18) months. Unless terminated pursuant to Commission order under IC 8-1-2.5-7, the termination of this Agreement shall not relieve Buyer of its executory obligations under Article VII of the Settlement.

ARTICLE 5- TERM

5.1 Unless modified by 5.2 below, the term of this Agreement shall commence on the first day of the month following issuance of a final order in Cause No. 42973 and end on March 31, 2011. If for any reason this or a successor Agreement is not in effect after March 31, 2011, this Agreement shall continue on a month-to-month basis until arrangements are made by Buyer to acquire services by some other means.

5.2 Notwithstanding 5.1 above, this Agreement may be terminated prior to March 31, 2011 by either Party in the event of the failure by either Party to perform in any material respect any covenant or obligation set forth in this Agreement, and such failure is not excused by force majeure or cured within fifteen (15) business days after written notice thereof to the Party failing to perform; provided, however, if such failure is incapable of being cured within such fifteen (15) business day period and the Party failing to perform has commenced and is diligently pursuing a cure, such period shall be extended for such time as is reasonably necessary to cure such failure up to ninety (90) days.

5.3 This Agreement is conditioned on the continued solvency of Buyer and Seller. If one Party becomes insolvent or seeks bankruptcy relief, the other Party may prospectively terminate this Agreement upon prior written

notice without further obligation other than to pay for services or Gas previously provided. In such a circumstance, the Parties will implement wind-up provisions designed to continue reliable provision of service and delivery of Gas.

ARTICLE 6- CHANGES TO APPENDICES

- 6.1. The Parties agree to review Appendices attached to this Agreement annually and as necessary to make required adjustments to Buyer's supply services. Such changes shall be consistent with the Agreement terms. Such changes also will be consistent with Section 3.4 (2) of the Settlement, which provides for possible adjustments in delivery services for the periods April 1, 2007 through March 31, 2009, and April 1, 2009 through March 31, 2011. The annual, monthly, and daily deliverability of Buyer's Appendix Services will be designed to most effectively match Buyer's overall sendout requirements.
- 6.2. Prior to June 15th of each year Buyer shall submit to Seller peak day and annual demand data for both a normal and severe season plan in a monthly baseload and usage per degree day format. The foregoing information is critical to Seller's role of optimizing Buyer's portfolio and assisting in the determination of the most efficient set of Appendix Services for Buyer.

ARTICLE 7- OPERATIONS

- 7.1. Buyer and Seller agree to accept for purposes of this Agreement the applicable quality, delivery pressure, measurement and other applicable rules, procedures, guidelines, tariff provisions, contractual arrangements and policies of suppliers or Transporters, as the same may change from time to time.

ARTICLE 8- FORCE MAJEURE

- 8.1. All obligations of the Parties to this Agreement shall be suspended while and only for so long as compliance is prevented by a cause beyond the control of the Party claiming force majeure, such as an Act of God, war, civil disturbance, operational or performance failure or declaration of force majeure by a supplier, leased storage field operator, Transporter, or other service provider, operational flow order(s), federal or state or local law, or binding order of a court or governmental agency, provided the suspension shall be only to the extent performance was prevented by the event of force majeure. A Party claiming force majeure hereunder shall have the duty to make all reasonable efforts to remedy the force majeure condition as promptly as possible.

- 8.2. Notice of force majeure must be provided with reasonably full particulars to the other Party at or near the time the Party becomes aware of the force majeure. Notice shall be provided to the designated representatives for Buyer or Seller designated in Appendix F.

ARTICLE 9- TRANSPORTATION PENALTIES

9.1. Seller shall be liable for all imbalance or other penalties, cash-outs, or other costs imposed on Buyer or Seller by any third party, including without limitation Seller's upstream or other transporters and Transporters, to the extent that such penalties, cash-outs or other costs are caused by Seller's actions or inaction. Buyer shall be liable for all imbalance or other penalties, cash-outs, or other costs imposed on Buyer or Seller by any third parties, including without limitation Seller's upstream or other transporters and Transporters, to the extent that such penalties, cash-outs or other costs are caused by Buyer's actions or inaction.

ARTICLE 10- BILLING AND PAYMENT

10.1. Following each Contract Month, Seller shall furnish, or have furnished, an itemized statement to Buyer stating the amounts due Seller pursuant to this Agreement (the "Statement"). Following the receipt of Seller's Statement, Buyer shall make Payment by the due date. Invoice date, due date, and payment method shall be as specified in Appendix G.

10.2. Interest shall accrue on all late payments commencing on the applicable due date at the then current prime rate of J.P. Morgan, Chase Bank, or its successor, or the maximum lawful rate, whichever is lower.

ARTICLE 11- REMEDIES

11.1. If Seller fails to deliver scheduled Gas and such failure to deliver is not excused under Article 8 of this Agreement, then Seller shall reimburse Buyer for the amount of increased cost to Buyer of acquiring replacement Gas, as well as additional fees or penalties incurred as a result of such failure to deliver. The amount owed by Seller to Buyer hereunder shall be calculated as the product of (a) the difference, if positive, between the price paid for replacement Gas including any additional penalties, transportation, fuel and other variable costs incurred to receive such replacement Gas, and the then applicable commodity charge, and (b) the difference between the scheduled Gas and the quantity of Gas actually delivered by Seller. Buyer and Seller agree to act in good faith with respect to purchases of such replacement Gas so as to minimize Seller's obligations to Buyer under this Section.

11.2. If Buyer fails to receive scheduled Gas and such failure to receive is not excused under Article 8 of this Agreement, then Buyer shall reimburse Seller in an amount calculated as the product of (a) the difference, if positive, between the then applicable commodity charge and the price received from a third party purchaser, including any additional penalties, transportation, fuel and other variable costs incurred to deliver Gas to a third party purchaser, and (b) the difference between the scheduled Gas and the quantity of Gas actually received by Buyer. Seller and Buyer agree to cooperate in good faith so as to minimize Buyer's obligations to Seller under this Section.

11.3. Should the Commission impose enforcement penalties on Buyer which were caused by Seller's intentional non-compliance with the Settlement, Seller shall indemnify and hold harmless Buyer for such penalties, and any costs, fees, or expenses associated with defending such action.

ARTICLE 12- CORRESPONDENCE

12.1. Except as provided in Section 8.2, any notice, statement or bill shall be in writing and shall be duly delivered when (a) mailed, postage prepaid, by registered, certified, or first-class mail, or (b) sent by prepaid overnight delivery to the applicable address, or (c) sent by hand delivery, or (d) sent by facsimile directed to the appropriate person and facsimile number with hard copy also delivered as in (a), (b), or (c) above. Addresses, telephone numbers, and facsimile numbers are specified in Appendix F.

ARTICLE 13- MISCELLANEOUS

13.1. This Agreement is subject to all applicable laws, orders, rules, and regulations of any state or federal governmental body or official having jurisdiction and both Seller and Buyer agree that the transactions agreed to hereunder shall be conditioned upon compliance with all such laws, orders, rules and regulations.

13.2. Seller and Buyer expressly agree that laws of the State of Indiana shall govern the validity, construction, interpretation, and effect of this Agreement.

13.3. Either Party may pledge, mortgage, or assign its rights hereunder as security for indebtedness. This Agreement is otherwise non-assignable except with the prior written consent of Buyer and Seller.

13.4. Notwithstanding any other provisions herein, the Parties hereto waive any and all rights, claims, or causes of action arising under this Agreement for incidental, consequential or punitive damages. Buyer shall have the right to enforce any and all terms of this Agreement against Seller. To the extent performance of this Agreement by either Party conflicts with the Settlement, the Parties will take corrective action in order to ensure that performance is in accordance with the Settlement. The Parties acknowledge that a failure to take timely and appropriate corrective action may subject Buyer to compliance measures by third parties pursuant to Article VII of the Settlement.

13.5. The Parties acknowledge that their respective business records and information are confidential in nature and may contain proprietary and trade secret information. Notwithstanding the foregoing, Seller agrees to provide Buyer access to those records required to verify Seller's statements to Buyer. To the extent access to information is necessary consistent with the Settlement, appropriate protection of proprietary and trade secret information will be afforded.

13.6. No waiver by either Party of one or more defaults or breaches by the other in performance of any of the terms or provisions of this Agreement shall operate or be construed as a waiver of any future default or breach, whether of a like or of a different character.

13.7. The terms and conditions contained in this Agreement and its Appendices herein constitute the full and complete agreement between the Parties and any change to be made must be submitted in writing and executed by both Parties. The Parties acknowledge that this Agreement is effective and must be carried out and enforced in a manner consistent with the Settlement.

13.8. Each Party represents that it has all necessary power and authority to enter into and perform its obligations under this Agreement and that this Agreement constitutes a legal, valid and binding obligation of that Party enforceable against it in accordance with its terms, except as such enforceability may be affected by any bankruptcy law or the application of principles of equity.

13.9. In the event any of the terms, covenants or conditions of this Agreement, or any amendment hereto, or the application of any such terms, covenants or conditions shall be held invalid as to any Party or circumstance by any court having jurisdiction, all other terms, covenants, or conditions of this Agreement, or any amendment hereto, and their application, shall not be affected thereby and shall remain in full force and effect.

13.10. If any provision of this Agreement is declared or rendered unlawful by a court of law or regulatory authority with jurisdiction over either of the parties or deemed unlawful because of a statutory or other change in the law, or if either Party suffers a substantial economic detriment due either to a determination relating to this Agreement by such an authority, or as a result of fundamental changes in the marketplace or other substantial changes in existing circumstances, the Parties will promptly meet to determine and negotiate a mutually acceptable agreement on such replacement provisions necessary to maintain the benefits and obligations that arise under this Agreement.

IN WITNESS WHEREOF, the Parties hereto have executed this Agreement in duplicate originals.

"SELLER"
PROLIANCE ENERGY, LLC

By: _____
John R. Talley,
President

"BUYER"
SOUTHERN INDIANA GAS AND ELECTRIC COMPANY, INC.

By: _____

Its: _____

Gas Sales And Portfolio Administration Agreement

APPENDICES INDEX

Appendices will be submitted to the Commission as a compliance filing following entry of an Order in Cause No. 42973.

Title	Appendix	Description
Buyer's Primary Delivery Points	A	List Primary Delivery Points on appropriate pipelines
Buyer's Maximum Quantities	B	Sets forth in Dth, by month and season, Buyer's Maximum Daily Quantities
Portfolio Information	C	Lists current Delivery Services
Supplier Reservation Costs	D	Lists Monthly and Seasonal Supplier Reservation Costs
Commodity Purchases-Gas Cost Incentive Mechanism	E	Incorporates the GCIM that is part of the Settlement Agreement
Notices	F	Addresses for purposes of notice to Seller and Buyer
Invoice/Payment Data	G	Sets invoice date and payment terms
Demand Cost Credit per Settlement	H	Sets Demand Cost Credit determined
Diversion of Entitlements	I	Entitlements diverted from and to Buyer
Portfolio Services	J	Specifics on portfolio services

Release of Anticipated Unused Entitlements

Introduction

Consistent with the obligations of the Settlement Agreement, the Utilities will implement a release process for 50% of the anticipated unused transportation entitlements.

The goals of the following processes to release anticipated unused entitlements are to: 1) promote competition, 2) provide nondiscriminatory open access, 3) generate the highest economic value consistent with reliable supply and 4) provide process transparency.

For all releases made pursuant to the processes described below, the Utility will determine whether entitlement packages are subject to recall or not, whether intraday recall will apply, and the availability of multi-month packages. In determining the need to make packages to be released subject to recall provisions, the Utility will consider the forecasted amount of available entitlements calculated under the Severe Season Annual Supply Plan and Design Day supply requirements. Recall provisions shall be designed to protect the reliability of system supply. Notwithstanding the foregoing, during the winter months (November through March) the entitlements sold with intraday recall terms will not exceed 75% of available entitlements; during the shoulder months (April, May, September and October) such entitlements will not exceed 50% of the available entitlements, and during the summer months (June, July and August) such entitlements will not exceed 25% of the available entitlements. As to the term of packages and the duration of any single release, apart from complying with all FERC requirements, the Utilities shall attempt to design entitlement packages in a manner that promotes bidding. In any event, bid package size of entitlements offered will not exceed 10,000 Dth per day.

Semi-Annual Pre-Arranged Release Process

This process applies to releases to be effective from November 1 through March 31 and releases to be effective from April 1 through October 31 of each annual period. By June 15th of each year, the Utilities will have determined the Normal Season Annual Supply Plan and Severe Season Annual Supply Plan. Prior to October 1st of each year, and in conjunction with the annual supply plans of each utility, the Projected Available Annual Entitlements ("Available Entitlements") will be established. Consistent with the Utilities' Gas Supply Planning Procedures, the annual supply plans will clearly identify the Available Entitlements.

Available Entitlements is equal to Total Transport Entitlements minus Normal Demand.

Total Transport Entitlements is the sum of the quantities of long haul pipeline transportation entitlements paid for by the utilities and reserved for the Utility's delivery services, excluding the net of planned transfers to and from the other Utility, as reflected in the Utility supply plans, and excluding entitlements that are not available because of a portfolio efficiency that has been documented and identified for sharing through the demand cost allocation procedure provided for in the Settlement, but including capacity reserved on Heartland Gas Pipeline and the upstream entitlements on Midwestern Gas

Transmission pipeline to the extent it is associated with Heartland delivery entitlements and necessary for providing service to Citizens under the Heartland Appendix Service.

Normal Demand is the projected quantity of firm long haul entitlement deliveries necessary to meet the normal weather consumption requirements of the Utility's firm customers.

The semi-annual pre-arranged entitlements release process will contain the following elements:

1. Entitlements available to be released under this process will be 50% of the Available Entitlements
2. By October 5th and March 5th of each annual period, the Utility will determine entitlement packages to make available for auction. The pre-arranged bidding process will begin no later than the tenth business day before the end of October and March. The Utility will provide notice of the process start date and time on its EBB no later than October 10th and March 10th. The start time will begin no later than 1:00 pm EST.
3. The pre-arranged bidding process, including posting of available bid packages, bid submissions by potential shippers, and process results will be conducted using a web-based platform. All other communications between the Utility and bidders will be in writing.
4. Bids will be public, meaning, on a real time basis during the bidding process, all bidders can view details of all bids, including, pipeline, volume, bid rate, and identity of submitting bidder.
5. The bidding period will last at least 48 hours. If a max rate bid or bids for the full entitlements in a given bid package are submitted within the first 2 hours of the bidding period, then the bidding period will terminate one hour after any such bid is posted. If more than one max rate bid is submitted for the same entitlement package, regardless of timing, the package volume will be allocated to the winning bidders on a pro-rated basis. For purposes of any such pro-rated allocation, bidders sharing any common parent shall be treated as a single bidder.
6. No later than the seventh business day before the end of October and March, the Utility will post the details of the winning bid(s) on the Utility EBB, which can be viewed by all bidders,
7. The Utility will notify administrator (ProLiance) no later than the seventh business day before the end of October and March so that ProLiance can post the prearranged entitlement release on the pipeline EBB(s).
8. Winning pre-arranged entitlement releases will be posted on the appropriate pipeline EBB no later the fifth business day before the end of October and March and, if not at max rates, will be subject to open bidding over two business days.
9. The winning bidder(s) from the Utility pre-arranged entitlement release process will have the right, which will be specified in the posting, to match the highest resulting bid offered on the pipeline EBB.

10. All postings and awards will fully comply with the respective pipeline tariffs and FERC regulation.
11. Once ProLiance has completed the release process on the EBBs, it will report back to the Utility.

Any packages made available but not receiving qualified bid(s) through the pre-arranged process will not be otherwise awarded in the semi-annual process. The unawarded volumes will, as determined by the monthly supply plans, become part of the monthly entitlement release process.

Monthly Pre-Arranged Release Process

No later than the eleventh business day before the end of each month, for releases to begin the first day of the upcoming month, and in conjunction with the monthly supply plans of each Utility, the Projected Available Monthly Entitlements will be determined. The Projected Available Monthly Entitlements will be computed as described above in the Semi-Annual Process. Consistent with the Utilities' Gas Supply Planning Procedures, the monthly supply plans will clearly identify: 1) the Projected Available Monthly Entitlements, 2) the entitlements previously awarded for the month pursuant to the Annual Pre-Arranged Release Process, and 3) the previously released entitlements for the month to be recalled to meet the projected consumption requirements of the Utilities' sales customers.

The Utility will conduct a monthly pre-arranged entitlement release process containing the following elements:

1. No later than the eleventh business day before the end of each month, the Utility will determine entitlement packages to make available for auction.
2. The pre-arranged bidding process will begin no later than the ninth business day before the end of each month. The Utility will provide notice of the process start date and time on its EBB no later than the 10th of each month. The start time will begin no later than 1:00 pm EST.
3. The pre-arranged bidding process, including posting of available bid packages, bid submissions by potential shippers, and process results will be conducted using a web-based platform. All other communications between the Utility and bidders will be in writing.
4. Bids will be public, meaning, on a real time basis during the bidding process, all bidders can view details of all bids, including, pipeline, volume, bid rate, and identity of submitting bidder.
5. The bidding period will last 24 hours. If a max rate bid or bids for the full entitlements in a given package are submitted, then the bidding period will terminate one hour after any such bid is posted. If more than one max rate bid is submitted for the same entitlement package, regardless of timing, the package volume will be allocated to the winning bidders on a pro-rated basis. For purposes of any such pro-rated allocation, bidders sharing any common parent shall be treated as a single bidder.

6. No later than the seventh business day before the end of each month, the Utility will post the details of the winning bid(s) on the Utility EBB, which can be viewed by all bidders,
7. The Utility will notify administrator (ProLiance) no later than the seventh business day before the end of each month so that ProLiance can post the prearranged entitlement release on the pipeline EBB(s).
8. Winning pre-arranged capacity releases will be posted on the appropriate pipeline EBB no later than the fifth business day before the end of each month and, if not at max rates, will be subject to open bidding over two business days.
9. The winning bidder(s) from the Utility pre-arranged entitlement release process will have the right to match the highest resulting bid offered on the pipeline EBB
10. All postings and awards will fully comply with the respective pipeline tariffs and FERC regulation.
11. Once ProLiance has completed the release process on the EBBs, it will report back to the Utility.

Monthly Capacity Auction Process

No later than the seventh business day before the end of the month preceding the upcoming month, the Utility will notify ProLiance of entitlements available for auction after the Annual and Monthly Pre-arranged Release Processes. ProLiance will auction the Utility-approved remaining Projected Available Monthly Entitlements by utilizing the pipeline EBB posting auction process. All entitlement postings will comply with the guidelines set forth by FERC and embodied in the pipelines' tariff. No later than the seventh business day prior to each month, each Utility will place on its website a summary of the entitlements available on each applicable pipeline to release in that upcoming month – this summary will not be updated during the month. The Utility will provide direct links to the pipeline websites.

Recall of Released Capacity

If it is determined that the Available Entitlements, net of capacity already released, are insufficient to meet the Normal Demand requirements of the Utilities, then any recallable capacity awarded through the above processes necessary to meet the Normal Demand will be recalled. To the extent it is necessary for capacity to be recalled to serve the Utility, the recalled capacity will consist approximately 50% of unused transportation entitlements retained by ProLiance and 50% of unused transportation entitlements not retained by ProLiance, as described in Section 4.4 of the Settlement. The determination of specific previously released volumes to be recalled will be made based upon the Utility's operational requirements and the economic value of the released capacity to the Utility, consistent with least cost supply planning. The Utility will utilize the pipeline default evaluation method (NPV). Released capacity will be recalled only for Utility service requirements.

Reporting

The Utility's release activity, including postings, sales and revenues will be summarized each month. Underlying documentation received from the pipelines will be retained for three years and will be made available for review, at any reasonable time, by authorized representatives of the Utilities, the OUCC, or the IURC pursuant to the Settlement, at any time and on such terms

as may be determined by agreement or order, and by authorized representatives of any person or entity pursuant to applicable discovery procedures in any regulatory or judicial proceeding.

Process Information and Review

The new release process will be established no later than April 1, 2006, provided the Settlement has been approved, but will not supersede release activity that has already occurred. Prior to implementation, the Utilities shall provide written notice to transportation customers and marketers that the new process will be implemented, including notification of the commencement date and an explanation of the process including a copy of this Exhibit. Information regarding the process shall be posted on the Utilities' websites. Any subsequent changes to the process will be similarly posted on the websites. Each Utility shall designate a representative who will handle all inquiries regarding the process. Within 90 days of implementation, the Settlement Parties may meet to review results and any issues that have arisen, and to the extent necessary, discuss process improvements. The Utilities will consider the input of the Parties, and may propose process modifications. Any material change must be agreed upon by the Parties or must be approved by the Commission.

Agreement On Gas Cost Incentive Mechanism (GCIM)

The Parties agree to a Gas Cost Incentive Mechanism ("GCIM") that provides risks and rewards for Gas supply acquisition performance compared to a market standard ("Benchmark"). The GCIM shall be effective upon IURC approval of the Settlement Agreement. To provide uninterrupted GCIM application, the currently effective GCIM terms shall remain in effect up to the date of IURC approval.

The Parties agree that the goals of the GCIM are: (1) reduce customer gas costs, (2) fairly measure costs of supply against market, (3) employ a measurement that recognizes the Utilities' specific portfolio characteristics, and (4) reward performance which beats the market and penalize performance that does not beat the market. The Parties recognize that these goals apply to the GCIM as a whole and that the benefits/costs accruing to the GCIM should be viewed in this context. Measurement models such as the benchmarking model are refinements to the GCIM process designed to measure the Utilities' success in meeting these goals. The Parties recognize that due to the evolving nature of natural gas markets, the model(s) used to measure the Utilities' performance relative to the above goals may need to be modified from time to time. *The Utilities' agree that they shall not solely rely on agreed to measurements when such measurements fail to meet the goals stated above and recognize that this issue is particularly important when new hedging and financial tools are implemented.* The Parties agree that in any future dispute regarding GCIM measurement calculations they will make every reasonable effort to resolve such

disputes through good faith negotiations aimed at achieving a result consistent with the above stated GCIM goals.

Subject to section III (A) below, the GCIM shall be effective through March 31, 2011, unless terminated earlier by the Commission or by agreement of the Parties. The Customers' share of GCIM dollars (described in Section I below) will promptly flow through to customers in the GCA. By separate agreement, the Utility (Citizens Gas, IGC and/or SIGECO) may pass its share of risks and rewards on to ProLiance Energy (its agent). The Utility may make reasonable use of financial tools for hedging purposes in its gas procurement efforts, and may recover such costs consistent with the GCIM and Section 3.4 (1) of the Settlement. This GCIM appendix consists of three sections: (I) GCIM Commodity Purchases, (II) Price Volatility Mitigation Program (PVMP) and (III) Additional Provisions.

I. GCIM COMMODITY PURCHASES

This section applies to and is intended to accommodate the types of monthly and daily commodity purchases frequently made by the Utility. This section does not apply to volumes purchased under the PVMP (see Section II).

A. Benchmark Prices. Benchmark Prices shall reflect the natural gas commodity prices for geographic locations representative of the supply basin/location where the gas was purchased and delivered to primary and secondary receipt points of the Utility's transportation capacity, and shall be separately calculated for each month of the year. In the event that the gas price

indices cited below are changed or eliminated by any of the below listed publications, and the substitute indices are similarly not available, then the Utility and the OUCC agree to negotiate in good faith to restore pricing terms that are economically equivalent.

(1) First of the month ("FOM") purchases. The applicable Benchmark Price(s) shall be the first of the month spot market natural gas commodity prices published in Platt's Inside FERC Gas Market Report ("IFGMR") as the "Prices of Spot Gas Delivered to Pipelines, [Applicable Month]." In the event the IFGMR is discontinued or unpublished, then the substitute reference for applicable FOM prices shall be Platt's Gas Daily Price Guide - "Monthly Contract Index."

(2) Other purchases. For purchases not based upon first of the month pricing and not covered by the PVMP program in Section II, the applicable benchmark prices shall be based upon "Daily" indices. The applicable Daily Benchmark Price(s) shall be the spot market natural gas commodity prices published in Platt's Gas Daily "Daily Price Survey, Midpoint." If the Gas Daily Daily Price Survey is discontinued or unpublished, then the substitute reference for applicable daily purchases shall be NGI's Daily Gas Price Index "Cash Market Prices."

B. Performance Evaluation. The Utility's performance under this Section I of the GCIM appendix shall be evaluated by multiplying the applicable Benchmark Price by the actual units purchased for each geographic location on a monthly basis to determine the Benchmark dollars for each geographic location.

If the Utility's actual natural gas commodity purchase dollars are less than the sum of the Benchmark dollars from all geographic locations, a positive differential exists. If the Utility's actual natural gas commodity purchase dollars are greater than the sum of the benchmark dollars from all geographic locations, a negative differential exists. Positive and negative differentials shall be shared between the utility and its customers as follows:

Negative Differential (Actual cost > Benchmark Price)

<u>% of Price Above Benchmark Price</u>	<u>% of Sharing Customer</u>	<u>% of Sharing Utility</u>
>4%	30	70
>2% to 4%	50	50
0% to 2%	70	30

Positive Differential (Actual cost < Benchmark Price)

<u>% of Price Under Benchmark Price</u>	<u>% of Sharing Customer</u>	<u>% of Sharing Utility</u>
0% to 2%	70	30
>2% to 4%	50	50
>4%	30	70

The calculation of the actual commodity costs shall include all relevant commodity costs and provide for a fair and reasonable comparison to published benchmarks. For example, to the extent the published benchmarks do not reflect commodity supply reservation fees, then such fees would not be included in the calculation of the actual commodity costs that are compared to the published benchmarks. Such reasonable costs may be recovered outside the GCIM in the Utility's GCA consistent with Section 3.4 (1) of the Settlement. The GCIM applies only

to gas commodity and, therefore, pipeline fixed or variable charges shall not be included in the GCIM. The Utility shall fully and properly account for its gas commodity costs and GCIM sharing dollars "above the line" on its books.

II. PRICE VOLATILITY MITIGATION PROGRAM (PVMP)

This section is intended to address commodity purchases and transactions made to mitigate gas price volatility (i.e., to help stabilize the Utility's retail natural gas prices), and is not necessarily intended to attain a price at or below index prices. The Utility may recover all reasonably incurred costs (such as reasonable brokerage fees and margin costs) associated with the PVMP, including the reasonable costs of financial tools used for hedging consistent with the Section 3.4 (1) of the Settlement. Some or all of the following types of purchases and transactions are specifically contemplated to mitigate price volatility.

A. Pipeline Storage Refill. Consistent with the past practices of Citizens Gas and Indiana Gas, the Utility will direct ProLiance to achieve a measure of price volatility mitigation in the refill of pipeline storage service quantities. The annual target volumes (the storage capacity to be filled) under this component are determined as of April 1 for every year by subtracting the volumes in inventory at April 1 from the target-ending inventory (after injections) per the Utility supply plans. The monthly gas cost (April through October of each year) is determined by dividing the total volume to be injected by seven (7) and multiplying the result by the applicable FOM indices each month for the applicable receipt point(s) for each storage service. In the event that pipeline

storage inventory is required by the Utilities to be withdrawn after April 1st for any month, of any program year, then the calculations will be adjusted as appropriate. ProLiance will invoice the total monthly cost for all applicable pipeline storage services to the Utilities each month, April through October for each year. The Utilities will retain their full rights to withdraw inventory volumes at deliverability rates corresponding to the applicable pipeline storage service tariffs and contracts. ProLiance will provide these volumes as agreed based on first of month pricing during the seven injection months as described above. ProLiance may pay more or less than the amounts billed the Utilities to refill pipeline storage; this risk and reward will be borne by ProLiance. ProLiance will, however, maintain detailed records of its actual and/or reasonably allocated costs to fill the Utility's pipeline storage capacity and shall make all arguably relevant records available to the OUCC or IURC upon request.

(B) Fixed Price Volumes (FPV). This component is modeled upon the current fixed price purchase program of the Utility. Generally, the Utility will decide on an on-going basis, whether prior to any year or during the then current year, to "lock in" or otherwise hedge the price of future gas purchases. Fixed prices will reflect the then current price represented by the NYMEX Gas Futures Exchange for the future month(s), plus location basis. The Utilities will lock in or hedge prices using either physical purchases with suppliers and marketers, which will reflect the location of the purchase, or using NYMEX futures contracts that reflect the Louisiana Henry Hub location. When NYMEX futures are used the Utility may also fix the appropriate location basis differential using *bona fide*,

documented, competitive basis quotes from reliable competitive market sources. The purchased NYMEX futures contracts later will be exchanged for physical gas commitments from suppliers prior to the month of gas delivery.

C. Other PVMP Transactions. The Utility may also request to recover costs for other reasonable transactions that are not specifically addressed directly above in II (B). This would include, but not necessarily be limited to, reasonable costs of "out-of-the-money" price caps (i.e., call options) that require an inexpensive premium but provide protection against very extreme market conditions. This would also include reasonable costs of "collared" contracts that provide commodity priced beneath a ceiling and above a floor price.

III. ADDITIONAL PROVISIONS

A. Periodic Review. The Utility and the OUCC may conclude a joint review of the GCIM during the term of this Exhibit E. Such review may include review of GCIM related provisions and issues, including, but not limited to, sharing ranges, price volatility mitigation components and the use of financial instruments. If disputes arise and good faith negotiations do not result in an agreement, then the Utilities will put forth their position before the Commission one-month after the conclusion of the joint review. The OUCC will then have one month to respond and put forth its position before the Commission. All reasonable efforts will be made to expedite Commission review and resolution of any disputes. During a review or any proceeding commenced under this paragraph, the then currently effective GCIM terms shall remain in effect until

modifications to the GCIM are approved by the Commission. Also, nothing in this paragraph is intended to limit the ability of the Parties from proposing *mutually agreeable* changes/improvements to the GCIM outside of the possible GCIM review established by this paragraph.

B. Transparency, Separations and Auditing. The GCIM reviews described directly above do not mitigate the need for appropriate and transparent record keeping by the Utilities and ProLiance (separate from other purchases for ProLiance's other business activities) and effective auditing and review by the OUCC to assure GCIM and GCA compliance.

C. GCA Review. The reasonableness of terms for all purchase transactions will be reviewable in the utilities' respective GCAs consistent with Section 3.4 (1) of the Settlement.

D. Extraordinary Relief. In extraordinary circumstances where the Utility to avoid pipeline penalties, requires intra-day gas, such purchases, if properly documented and demonstrated to be prudent, would be recovered outside the GCIM.

GAS SUPPLY PLANNING PROCEDURES

**FOR CITIZENS GAS & COKE UTILITY,
INDIANA GAS, AND SIGECO**

EFFECTIVE _____1, 2006

GAS SUPPLY PLANNING
For CITIZENS GAS & COKE UTILITY, INDIANA GAS, and SIGECO

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A. DEFINITIONS

"Agreement" shall mean the Settlement Agreement in Cause No. 42973.

"Procedures" shall mean the detailed procedures contained in this document, Gas Supply Planning Procedures.

"GCIM" shall mean Gas Cost Incentive Mechanism.

"Utility" and "Utilities" shall mean Citizens Gas & Coke Utility, Indiana Gas, and/or SIGECO, each individually or collectively as the context may indicate.

"Portfolio Administrator" shall mean and refer to ProLiance Energy, LLC.

"IURC" shall mean the Indiana Utility Regulatory Commission.

"OUCC" shall mean the Indiana Office of Utility Consumer Counselor.

B. GENERAL RESPONSIBILITIES

1. The Utilities will determine long term, annual, seasonal, monthly and daily supply plans, and in doing so may request and consider input from the Portfolio Administrator. The Utility shall have access to all information necessary to prepare and evaluate its supply plans. The Utility's Vice President of Gas Operations (or another designated Utility officer) shall have overall responsibility and control of the supply planning process.
2. At least annually, the Utilities shall meet with each other and with the Portfolio Administrator to determine whether and to what extent individual capacity additions required in their respective supply plans can be minimized prior to actual purchases of incremental capacities.
3. The Portfolio Administrator will manage the pipeline contract scheduling and gas procurement activities for the Utilities, in accordance with the Agreement.
4. The Utilities will communicate system demands, forecasts, capabilities, and limitations to the Portfolio Administrator on a long-term, annual, monthly and daily basis. Annual and monthly demand forecasts

provided by the Utility will be based on both normal and severe season planning assumptions.

5. Portfolio Administrator will provide supply at prices consistent with Utility's policy of obtaining long-term, firm, reliable supply at the lowest gas cost reasonably possible, consistent with the applicable terms of the Agreement, GCIM and operational requirements and limitations.
6. Each Utility shall have regularly scheduled meetings and other communications with Portfolio Administrator as necessary to convey the Utility's periodic requirements and to ensure Utility's gas supply plans and needs are being properly met.
7. Utilities will work collaboratively to optimize the Utilities' supply resources in order to create synergies where possible to reduce costs. The Utilities may include Portfolio Administrator in such efforts.

C. COMBINED PORTFOLIO ANALYSIS AND PLANNING

Delivery services provided to the Utilities by the Portfolio Administrator are dependent, in part, on synergies created by the management of the combined portfolio by the Portfolio Administrator. Maintaining Utility resource capabilities to meet the delivery obligations efficiently, reliably and at the least cost reasonably possible will be incorporated in the supply planning process and resulting supply plans.

With respect to annual and other long-term supply plans, the Utilities shall determine their own supply requirements and independently prepare their own plans for the level and type of supply resources required for system supply. In connection with the preparation of annual and other long-term supply plans, the Utilities will communicate with each other and the Portfolio Administrator to share data relevant to the identification of potential synergies and portfolio efficiencies. Data to be provided by the Utilities will include firm demand forecasts, for both normal and severe season, by pipe, including forecasted transportation customer deliveries.

The Utilities will provide the required data on or before June 15th of each year. Following review and analysis, the Utilities will then meet with each other and work collaboratively and with the Portfolio Administrator in an effort to identify and assess potential synergies arising from the use of a joint portfolio administrator.

In connection with the annual and other long-term supply planning process, the Utilities may share data with Portfolio Administrator and consult with Portfolio Administrator in an effort to identify and assess potential synergies. In no event, however, shall supply planning responsibility be delegated to Portfolio Administrator. The Utilities will work collaboratively, and may include the Portfolio Administrator, to optimize the Utilities' supply resources in order to create synergies and reduce costs.

D. SPECIFIC RESPONSIBILITIES - UTILITY

Each Utility shall be responsible for the following:

1. Determining long-term, annual, seasonal (as required), monthly, and daily supply plans. Each year, Utility will analyze and adjust annual supply plans based on yearly updated demand forecasts that include base load and usage per degree day factors.
2. Selection of the design peak day and severe winter planning criteria and determining the appropriateness of any capacity reserve margin.
3. Providing to Portfolio Administrator annual supply plans (normal and severe season cases) by June 15th of each year.
4. Determining available entitlement release volumes for each pipeline supplier included in the annual, seasonal, and monthly supply plans.
5. Determining a Daily Gas Supply Plan specifying deliveries to Utility's city gate by pipeline.
6. Determining the storage entitlements to use in its supply plans.
7. Being available daily to discuss daily supply plans by 7:45 a.m. Central Clock Time.
8. Maintaining a record of all Utility-approved long-term, annual, seasonal, monthly, and daily supply plans for three years. The Utility will make all plans available for review by the OUCC.
9. Operating the Utility system to meet the agreed-upon supply plans, subject to safe operation of all Utility pipeline systems and facilities.

10. Making all decisions regarding customer curtailment or interruption on the Utility system, and making all decisions regarding the need for, timing and extent of any Utility-called operational flow orders.
11. Planning for and utilizing resource capabilities such that synergy-related obligations can be met.
12. Maintaining relationships with operating personnel concerning operation and maintenance of facilities between Utility and the interstate pipeline companies and third parties serving the Utility system.
13. Presenting and supporting the prudence of Utility's pipeline transportation and leased storage portfolios, as well as gas supply purchases in proceedings before the IURC.
14. Presenting and supporting the prudence of the long-term, annual, monthly and daily supply plans in proceedings before the IURC.
15. Determining the need for, timing and extent of any recall of released entitlements, communicating as appropriate, and monitoring to ensure system supply and integrity requirements are maintained.
16. Providing timely, detailed demand forecast data and analysis to the other Utilities and Portfolio Administrator in order to investigate, develop, and implement cost savings strategies in connection with developing annual and other long-term supply plans.
17. Maintaining sole, final decision-making authority with respect to all supply plans.

E. SPECIFIC RES PONSIBILITIES – PORTFOLIO ADMINISTRATOR

Portfolio Administrator shall be responsible for the following:

1. Promptly reviewing and evaluating each long-term, annual, monthly or daily supply plan (including the projected available entitlement release volumes for each delivery point) as necessary to comply with the Agreement and these Procedures.
2. Scheduling (including nominations) of gas supplies, pipeline transportation and leased storage deliveries for the Utility each day.

3. Posting available entitlement release volumes on pipeline electronic bulletin boards according to the Agreement and pipeline tariff.
4. Providing timely and accurate reporting of Portfolio Administrator's gas deliveries to the Utility pipeline delivery points, including pipeline storage delivery points.
5. Providing timely notice of the applicable pipeline contract imbalance tolerances to allow Utility to make any necessary arrangements to balance each day.
6. Providing data and support necessary for Utility to present and support the prudence of its supply planning portfolio and long-term, annual, monthly, and daily supply plans in proceedings before the IURC. This data and support will be in the form of supply reports and will include daily system supply quantities, base and swing gas supply purchase quantities, contract storage quantities, and other data related to supply planning and balancing.
7. Providing support and data necessary for Utility to verify monthly invoices. This support will include information contained in the daily supply reports.
8. Providing support and detailed data necessary to accommodate Utility departments in meeting internal and external reporting deadlines.
9. Providing a monthly summary of the actual daily gas purchase prices by day to Utility no later than the first business day of the following month.
10. Providing a monthly contract storage activity report by the third business day of the following month.
11. Providing monthly invoice data to Utility by the third business day of the following month.
12. Providing data, records and information to the OUCC and/or to an outside auditor selected by the OUCC in accordance with the Agreement, as may be necessary and appropriate to assist the OUCC in monitoring the supply planning process and all support and assistance provided by Portfolio Administrator with respect to supply planning, subject to agreed confidentiality protections.

F. LONG-TERM SUPPLY PLAN

1. The long-term supply plan shall consist of the current year's annual supply plan and the following four years' annual supply plans.
2. The long-term supply plan shall consider, but not necessarily be limited to Utility's projected long-term demands, its storage injection and withdrawal requirements, peaking facility changes, customer growth, supply portfolio changes, supply contract changes, major system enhancements, and any relevant operational factors.
3. In connection with the long-term planning process, the Utilities shall determine their own supply requirements and independently prepare their own plans for the level and type of supply resources required for system supply.
4. In connection with the long-term planning process, the Utilities will communicate directly with each other and will work collaboratively and with the Portfolio Administrator to optimize the jointly administered supply portfolio in order to create synergies and reduce costs where possible. The Utilities will share with each other and the Portfolio Administrator data including demand forecasts and analyses of supply options in an effort to investigate, develop and implement demand cost savings strategies.
5. There will be no delegation of supply planning responsibility to Portfolio Administrator.

G. ANNUAL SUPPLY PLAN

1. The procedures applicable to long-term supply planning will be followed in connection with the preparation of annual supply plans.
2. The annual supply plan shall be used as the guide for the upcoming season's monthly supply plans.
3. The annual supply plan shall clearly identify the projected available annual entitlement release volumes.

H. MONTHLY SUPPLY PLAN

1. Each month Utility and Portfolio Administrator personnel shall meet for the purpose of reviewing the gas supply plan for the upcoming month.

2. Based upon criteria established in the annual supply plan, with modifications for actual weather and storage levels, Utility shall specify the anticipated quantities of gas that shall be purchased on a base load basis for the upcoming month for the Utility system.
3. Utility shall specify the initial pipelines which will be delivering monthly base load gas to Utility's system and the amounts of base load gas to be delivered at each pipeline delivery point within system limitations.
4. Base load quantities scheduled at the first of the month shall not change unless mutually agreed to by Portfolio Administrator and Utility.
5. Base load nomination quantities will be provided at prices and terms in accordance with the provisions of the Agreement.
6. Monthly supply plan utilization of company storage will be consistent with preserving deliverability specified in the annual supply plan or changes directed by Utility.
7. The monthly supply plan shall clearly identify the projected available monthly entitlement release volumes, entitlement release volumes previously posted pursuant to the annual supply plan, previously released entitlements to be recalled to meet the requirements of Utility, and any previously released entitlements that were recalled, detailed by delivery point. Decisions with respect to entitlement availability and recall will be made by Utility.
8. Utility will provide timely, detailed forecast data and analysis to Portfolio Administrator to assist in investigating, developing and implementing cost saving strategies. Utility will independently analyze, approve and maintain responsibility for its monthly supply plans.

I. DAILY SUPPLY PLAN

1. Utility and Portfolio Administrator personnel shall communicate daily by 7:45 a.m. Central Clock Time for the purpose of discussing the current day and establishing a proposed supply plan for the next day and following three days.
2. Utility shall notify Portfolio Administrator of any requested changes to its expected current daily demand as soon as they are known. Portfolio Administrator will make all reasonable efforts to accomplish current day scheduling changes as necessary.

3. Utility shall specify the daily swing quantities above the baseload quantities nominated at the beginning of the month, and the utilization of company and contract storage.
4. Portfolio Administrator shall schedule the gas supply and transportation and storage contracts necessary to meet the daily supply plan requirements.
5. Utility shall establish a daily sendout pattern in order to achieve the approved daily supply plan. Utility shall use, as necessary, the daily swing tolerances specified in the approved daily supply plan to balance system supply and demand.
6. Utility may request intra-day scheduling changes consistent with pipeline allowances and Utility operational capabilities.
7. Utility may request intra-day supply changes due to weather changes, or operational or economic considerations. Any such changes to the confirmed supply deliveries will be reported verbally to Gas Control at Utility by Portfolio Administrator and followed up on paper later that day.
8. The daily supply plan shall clearly identify the entitlement release volumes previously posted pursuant to the annual (and/or seasonal) and monthly supply plans, previously released entitlements to be recalled to meet the requirements of Utility, and any previously released entitlements that were recalled. Portfolio administrator will identify entitlement release amounts detailed by delivery point. Decisions with respect to recall will be made by Utility.
9. In connection with daily supply planning, Utility may request that Portfolio Administrator run planning models or otherwise assist in determining supply requirements, but Utility will independently analyze, approve and maintain responsibility for its supply plans.

Appendix G

Anticipated Unused Entitlements Value Sharing

Narrative Description

The intent of this Appendix G is to specify the method by which the value generated from the unused entitlements available to ProLiance is determined and to provide ratepayers with a share of that value. To the extent issues arise which may not be specifically or completely addressed herein, the OUCC and ProLiance agree that the issues will be determined consistent with the above stated intent.

ProLiance and the OUCC, through the exchange of data and analysis, have each assessed the value of unused entitlements subject to sharing, and compromised for purposes of this Settlement. A negotiated value will be shared with Utility customers as a credit to the GCA.

During the term of the settlement, the negotiated value is as follows:

Time Period	Shared Value
April 1, 2006 through October 31, 2007	\$5.1 Million per year, credited in monthly amounts, prorated in proportion to projected entitlements

The **Measurement Year** under this Appendix shall be the November 1, 2006 to October 31, 2007 period. ProLiance will provide information to the OUCC regarding **Projected Entitlements and Entitlement Values, no less than quarterly, beginning with the quarter commencing July 1, 2006.** Because of changing market conditions affecting the capacity value, the actual entitlements available during the year, as well as multi-month or annual market sales, the information is considered a guide only, and will not be used to "true-up" the actual value shared as determined by the negotiated amount. For the purpose of this audit comparing actual market value to the negotiated Shared Value Payment, the following definitions apply:

Projected Entitlements, are the projected available entitlements, by pipeline, and by month, based on the Utility's annual supply plan.

Total Transport Entitlements is the sum of the quantities of longhaul pipeline transportation entitlements paid for by the Utility and reserved for the Utility's

delivery services, excluding the net of planned transfers to and from the other utilities, as reflected in the Utility's Annual Supply Plan, and excluding capacity that is not available because of a portfolio efficiency that has been documented and identified for sharing through the demand cost allocation procedure provided for in the Settlement, but including entitlements on Heartland Gas Pipeline and the upstream entitlements on Midwestern Gas Transmission pipeline to the extent it is associated with Heartland delivery entitlements and necessary for providing service to Citizens under the Heartland Appendix Service.

The **Entitlement Value**, is a weighted average unit rate expressed in \$/Dth of the rate payer share of net margin for bundled sales using excess Utility capacity. The Entitlement Value will be determined by pipeline, by adjusting the actual sales prices for the delivered bundled sales to **Market Customers** by the applicable costs of those sales

Market Customers are ProLiance's Indiana industrial and commercial customers with use more than 5000 Dth/year at facilities served by Vectren or Citizens and which are eligible for gas transportation.

Within sixty days after the conclusion of the **Measurement Year**, ProLiance will make available a calculation of **Entitlement Value** for review by the OUCC in determining the appropriate Shared Value mechanism applicable on a prospective basis. For OUCC review purposes, ProLiance will also make available, beginning with the quarter commencing July 1, 2006, to the OUCC under strict confidentiality restrictions, the sales price data and cost data underlying the calculation of overhead used by ProLiance in its calculation of Entitlement Value for **Market Customers** called for by this Appendix. ProLiance will also make available the **Projected Entitlement** data, actual sales price data and cost data underlying the calculation of overhead used by ProLiance in its calculation of Entitlement Value data for other industrial and commercial customers on the pipelines on which ProLiance received **Projected Entitlements** under this Appendix. Access to all data provided shall be under a confidentiality order and/or agreement and restricted so that **Market Customers**, competitors of ProLiance, and other entities shall not have access to the highly confidential, proprietary pricing strategy formula data or the actual sales data information produced for audit under this Appendix. No use of the data by the OUCC will reference or reveal customer identities or provide information sufficient to identify particular customers. After its review, the OUCC will also calculate an Entitlement Market Value and provide it and the underlying analysis to ProLiance by March 15, 2008. The OUCC and ProLiance will then meet to negotiate any variances in the two calculations and to specify by April 30, 2008 a new Shared Value mechanism under the Settlement for the period from November 1, 2007 until the conclusion of the settlement period. In the absence of agreement on the new Shared Value Mechanism either may seek a determination of an appropriate Shared Value in a manner consistent with the Settlement goals from the IURC by filing a petition no earlier than May 1, 2007 and no later than May 31, 2008.

AFFILIATE GUIDELINES FOR CITIZENS GAS & COKE UTILITY

INTRODUCTION

The Indiana Office of the Utility Consumer Counselor ("OUCC") and the Board of Directors for Utilities of the Department of Public Utilities of the City of Indianapolis, As Successor Trustee of a Public Charitable Trust, dba Citizens Gas & Coke Utility ("Utility") and others (collectively "Parties") have negotiated in connection with Cause No. 42233 and Cause Nos 37394GCA50S1 and 37399GCA50S1 ("GCA50S1") the following Affiliate Guidelines to govern the relationships between the Utility and its Affiliates. The Parties agree that these guidelines will be submitted to the Indiana Utility Regulatory Commission ("IURC") for its review and approval in GCA50S1. The Parties intend for the guidelines to be enforced by the IURC, and they shall become effective upon their approval by the IURC. The OUCC and Utility may, through negotiation and agreement, jointly petition the IURC for modifications to these Affiliate Guidelines, in which case they shall have the burden of jointly proving any proposed change is in the public interest considering all relevant factors, including, but not limited to, price of service and the impact on competition. If either the OUCC or Utility desires changes to these Affiliate Guidelines and is unable to obtain agreement from the other party for such changes, then that party may petition the IURC for the desired changes and individually bear the burden of proving that such changes are in the public interest; however, any such petition shall not be filed without the petitioner first attempting to obtain the agreement of the other party. Subject to the following sentence, anyone else seeking a change to these Affiliate Guidelines may also petition the IURC and would bear the burden of proving that the proposed changes are in the public interest. However, any such petition shall not be filed without the Utility and the OUCC first being notified and given a reasonable opportunity to consider the proposed change. The Commission may also make modifications to these Affiliate Guidelines on its own motion, after notice and a hearing.

Subject only to the Settlement Agreement and ARP approved in GCA50S1 and Cause No. 42233, the Affiliate Guidelines and the Cost Allocation Guidelines govern all current and future affiliate relationships between the Utility and its Affiliates. The Commission may approve an Affiliate contract that differs from these Affiliate Guidelines if the Utility files a petition requesting an exception from these Affiliate Guidelines and satisfies its burden in establishing such contract is in the public interest considering all relevant factors, including, but not limited to, price of service and the contract's impact on competition.

DEFINITIONS

The definitions below apply to terms used in the Affiliate Guidelines and the Cost Allocation Guidelines.

"Affiliate" "Affiliate" means a Person that is an affiliated interest for purposes of I.C. 8-1-2-49 or that is otherwise found to be an "Affiliate" by the Commission or otherwise is an "Affiliate" under Indiana Law.

"Person" "Person" includes the following: (a) individual, (b) corporation, regardless of type or state or country of incorporation, (c) unincorporated association, (d) company, whether limited liability or otherwise, and (e) business trust, estate, partnership, trust, two (2) or more Persons having a joint or common economic interest, and any other entity.

"Commission" "Commission" means the Indiana Utility Regulatory Commission.

"IURC" "IURC" means the Indiana Utility Regulatory Commission.

"OUCC" "OUCC" means the Indiana Office of Utility Consumer Counselor.

"Competitive Terms" "Competitive Terms" means the best terms reasonably available in the competitive marketplace at that time (including the terms available from the Utility itself under efficient operation), giving due consideration to both price and non-price terms such as quality and reliability. If the Utility can provide the services at the lowest cost with comparable quality and reliability, then that cost shall be considered the "Competitive Terms."

"Capital Costs" "Capital Costs" means the costs associated with obtaining the financial capital required to provide physical assets such as office buildings, computers or office equipment.

"Non-Regulated" "Non-Regulated" means not regulated by the IURC. "Non-Regulated" also applies to products or services over which the IURC has declined its jurisdiction.

"Shared Corporate Support Services" "Shared Corporate Support Services" means the following types of functions/services that the Utility may share with its own and its Affiliates' non-regulated operations: (1) accounting and corporate treasury services; (2) human resources; (3) information technology and communications services; (4) directors and officers services; (5) legal services; (6) insurance and claims; (7) billing; (8) customer call center services; (9) facility and fleet management; and (10) environmental services.

"Similarly-Situated" "Similarly-Situated" means having general characteristics in common such as belonging to the same rate class or operating in the same or similar industries. A Utility-affiliated gas or power marketer would, for example, be considered similarly-situated to non-affiliated gas or power marketers.

GENERAL AFFILIATE GUIDELINES

- A. No Cross-Subsidies.** The Utility shall not subsidize its Affiliates or its non-regulated operations.
- B. Separation of Regulated and Non-Regulated Operations.** The separation of the Utility's regulated operations from its own and its Affiliates non-regulated operations is necessary to prevent potential cross-subsidies. To the maximum extent practicable, the Utility shall separate its regulated operations from its own, and its Affiliates non-regulated operations. Instances where such separation does not exist must otherwise be in compliance with these Affiliate Guidelines and the Cost Allocation Guidelines.
- C. No Discrimination.** The Utility shall not discriminate in favor of or otherwise give preferential treatment to its Affiliates, its Affiliates' customers or the Utility's own non-regulated operations.
- D. Comparability of Service.** The Utility shall provide comparable service to all Similarly-Situated marketers, customers or other entities, regardless of affiliation.
- E. Procurement on Competitive Terms.** The procurement of goods, services, assets and other resources by the Utility shall be on Competitive Terms, consistent with the public interest and in compliance with these Affiliate Guidelines and the Cost Allocation Guidelines. The Utility may procure services from an Affiliate but such procurement must be done on Competitive Terms.

SPECIFIC AFFILIATE GUIDELINES

- 1. The Utility's Affiliates and its non-regulated operations shall be charged for all costs incurred on their behalf. These costs shall be appropriately and reasonably allocated by the Utility and shall include, but not be limited to, costs associated with shared facilities, general and administrative support services and other corporate overheads.
- 2. The Utility shall process all similar requests for service in the same manner and within the same reasonable time period for all Similarly-Situated customers, marketers, and other entities, regardless of affiliation.
- 3. The Utility shall not give preference to or discriminate in favor of its Affiliates, its Affiliates' customers or its own non-regulated operations in matters including, but not limited to, the allocation, assignment, release, or transfer of rights to intrastate or interstate capacity, use of

Utility distribution facilities, storage on system, rights to storage off system, or in the sale of gas.

4. The Utility shall not condition or tie any agreement to provide Utility service to any agreement relating to a service to be provided by an Affiliate.
5. To the maximum extent practicable, Utility employees shall function separately and independently from employees of Affiliates and those engaged in non-regulated operations including, but not limited to, gas marketers, power marketers and other service providers.
6. The Utility may not, through tariff or otherwise, give any Affiliate or an Affiliate's customer or any non-regulated operation a preference or an advantage with respect to the transportation of gas including, but not limited to, the movement or delivery of gas on its distribution system, the administration of customer contracts, scheduling, nomination, balancing, metering, storage, backup service, curtailment priority, or billing/invoice disputes.
7. The Utility shall apply tariffs and their provisions and all other aspects of utility service on a consistent and non-discriminatory basis to all Similarly-Situated marketers, customers, and other entities regardless of affiliation.
8. Any discount or rebate for utility service offered by the Utility to an Affiliate or an Affiliate's customer shall be offered on a non-discriminatory basis to all Similarly-Situated marketers, customers or other entities, regardless of affiliation. If the Utility waives a penalty or fee related to utility service for an Affiliate or an Affiliate's customer, it shall waive such penalty or fee for Similarly-Situated Persons on a non-discriminatory basis.
9. The Utility shall not give preference to or discriminate in favor of its Affiliates or its Affiliate's customers in its provision of information. This includes, without limitation, information related to the sale or marketing of energy or energy services to existing or potential new customers and information related to the availability of transmission, distribution or storage capacity. Specific customer information shall be made available to affiliated or unaffiliated entities only upon consent of the customer or as otherwise provided by law or Commission rules or orders, except that customer name and address information may be provided to energy marketers or energy service providers.
10. The Utility's Affiliates and its non-regulated operations may share information technology and communications services with each other and the Utility. However, such sharing of information technology and

communications services shall not be done in a manner that violates Specific Guideline 9 above regarding the non-discriminatory provision of information. The Utility shall take whatever steps are necessary to fulfill this requirement such as, for example, the implementation of electronic "firewalls" or other measures to control access to Utility information.

11. The Utility shall not speak on behalf of its Affiliates or give the appearance that it speaks on behalf of its Affiliates. The Utility's Affiliates shall not speak on behalf of the Utility or give the appearance that they speak on behalf of the Utility.
12. Customer call handling shall be performed on a non-discriminatory basis without respect to affiliations of the customer or affiliations of the customer's marketer or energy service provider. If a customer requests information about alternative sources of supply, the customer service representatives shall offer to provide a list of all alternative suppliers known to be serving customers in the same rate class as the customer making the inquiry, except those suppliers excluded by mutual agreement of the Utility and the OUCC. Such a list may include Utility Affiliates, but the Utility customer service representatives shall not promote or endorse services offered by an Affiliate. The IURC and OUCC will be able to monitor compliance with the Guidelines through the provisions of access to customer calls.
13. The Utility's Affiliates shall not trade upon, promote, or suggest that they receive preferential treatment as a result of affiliation with the Utility.
14. The Utility and its Affiliates shall not participate in joint advertising. An Affiliate may, however, reference the fact of its affiliation with the Utility. Any such public references by the Affiliate shall not: (a) make the Affiliate appear to be the same as the Utility, or (6) suggest that the Affiliate or the Affiliate's customers will have any advantage as a result of the affiliation.
15. If the Utility combines charges for regulated energy services with charges for non-regulated energy services into a single bill, such a combined bill format will be made available on a non-discriminatory basis to non-affiliated entities that provide energy services in the Utility's service territory.
16. The Utility and its Affiliates shall maintain separate books and records, which shall be available for Commission inspection consistent with Indiana law.

17. The OUCC and its agents shall have access to officers and employees and access to the books and records of the Utility and its Affiliates as reasonably necessary to ensure compliance with these Affiliate Guidelines, the Cost Allocation Guidelines and Title 8 of the Indiana Code. If disputes arise regarding the reasonableness of the timing or scope of requested access to Affiliate and Utility books and records, if not resolved by the parties, then such disputes may be presented to the Commission through use of an alternative dispute resolution process as agreed upon by the OUCC and Utility. During this process, the OUCC shall bear the burden of demonstrating why it needs certain books and records and the Utility shall bear the burden of demonstrating the unreasonableness of the OUCC's request. In seeking a resolution of access disputes, the Parties agree that time is of the essence, and the intent of the Parties is that the Commission's review of such disputes will be facilitated by the Parties so that the review can be as expeditious as possible.
18. All complaints relating to these Affiliate Guidelines and the Cost Allocation Guidelines, whether written or verbal, shall be submitted to the Utility, attention: Director Budget and Rates or designated Utility counsel, who shall acknowledge to complainant by first class mail receipt of such complaint within five (5) working days of receipt. The Utility shall conduct a preliminary investigation of the complaint and prepare a written statement which shall contain the name of the complainant and a detailed factual report of the incident or incidents underlying the complaint, including all relevant dates, companies involved, employees involved, and the specific claim. A copy of the written statement shall be provided to the complainant. The Utility shall communicate the results of the preliminary investigation to the complainant in writing within twenty (20) days after the complaint was received, including a description of any course of action to be taken. In the event the Utility and the complainant are unable to resolve the complaint, the complainant may file a complaint with the Commission. Any complaint that is filed with the Commission before it has been submitted to the Utility under this section shall be held in abeyance while the procedures outlined here are followed. The Utility shall keep a log of all complaints for a period of not less than three (3) years and shall keep such log available for inspection by the IURC, OUCC and complainant.
19. All transactions between the Utility and its Affiliates shall be in accordance with a written contract filed with the IURC. The Utility shall maintain sufficient records of all such transactions for at least three (3) years so as to allow for a complete and thorough audit.
20. The Utility maintains that Ind. Code § 8-1-2-49 does not apply to it

because it is a municipally owned utility; however, without waiving its jurisdictional position, the Utility will file affiliate contracts of the types covered by Ind. Code §8-1-2-49 with the Commission. The Utility also agrees to meet with the OUCC to review proposed new Affiliate contracts. Upon filing of Affiliate contracts with the IURC, copies of such contracts will be delivered to the OUCC. Affiliate contracts shall be governed by Indiana law and these Affiliate Guidelines and the Cost Allocation Guidelines. To the extent the Affiliate Guidelines contain provisions or commitments that go beyond what would otherwise be required of the Utility under Indiana law, the Guidelines shall control. The OUCC may challenge such contracts, but if the OUCC makes such a challenge it shall have the burden of establishing that the contract or any provision thereof is not in the public interest.

PROCEDURES FOR FILING AFFILIATE CONTRACTS

All Affiliate contracts shall be filed with the IURC and be in conformance with the Affiliate Guidelines, the Cost Allocation Guidelines and Indiana law. Such contracts shall be available for public inspection, except to the extent that information is protected from public disclosure under Indiana law. Except to the extent set forth herein, these Affiliate Guidelines in no way affect, or expand, the IURC's duties and/or authority under Indiana law to *inter alia* investigate such contracts, hold public hearings related to such contracts and/or approve or disapprove such contracts.

ANNUAL INFORMATIONAL FILING

The Utility shall file annually with the Commission, and provide a copy to the OUCC, the following information concerning the Utility's Affiliates and its non-regulated operations.

1. The names and business addresses of the officers and directors of each Affiliate that has transacted any business with the Utility during the previous twelve (12) months. For each such Affiliate, the Utility shall also provide the following in its annual informational filing:
 - a. The Affiliate's name and a description of the Affiliate's primary line(s) of business and a description of the nature of the Affiliate's business with other non-affiliated entities.
 - b. A schedule detailing and summarizing the nature and dollar amounts of the transfers of assets, goods and services between the Utility and the Affiliate that took place during the applicable twelve-month period.
2. A listing of all contracts currently in effect between the Utility and Affiliate(s) indicating the subject matter of the contract, the date the

contract became effective and the contract's expiration date.

3. A corporate organization chart, which shows the Utility, its Affiliates, and their relationships to one another.
4. A description of the method(s) used to identify, value, and record transfers of assets, goods and services between the Utility and its Affiliates.
5. A description of sharing of personnel between the Utility and its Affiliates during the twelve-month period.
6. A log of complaints maintained by the Utility under Specific Guideline 18.
7. A listing and description of all non-regulated operations engaged in by the Utility, including the amount of revenues and expenses generated by each such non-regulated operation.

These annual informational filings shall commence ninety (90) days after entry of the Commission's Order approving these Affiliate Guidelines, and shall repeat thereafter on or before April 30 of each year, as part of the Utility's Annual Report filing with the Commission. These annual informational filings shall not serve, or be interpreted, as a pre-approval process.

APPENDIX B

COST ALLOCATION GUIDELINES FOR CITIZENS GAS & COKE UTILITY

INTRODUCTION

The OUCC and Citizens Gas & Coke Utility. ("Utility") and others (collectively "Parties") have negotiated in connection with Cause No. 42233 and GCA50S1 the following Cost Allocation Guidelines to govern the allocation of costs between the Utility and its Affiliates. The OUCC retains all of its rights and authority to dispute the reasonableness of and/or recovery of all Utility costs, including those to which these Cost Allocation Guidelines may be applicable. Mere allocation of costs under these guidelines does not predetermine the reasonableness of rate recovery of such costs. The Parties agree that these guidelines are intended to be enforced by the IURC, and they shall become effective upon their approval by the IURC. The OUCC and Utility may, through negotiation and agreement, jointly petition the IURC for modifications to these Cost Allocation Guidelines, in which case they shall have the burden of jointly proving any proposed change is in the public interest considering all relevant factors, including, but not limited to, price of service and the impact on competition. If either the OUCC or Utility desires changes to these Cost Allocation Guidelines and is unable to obtain agreement from the other party for such changes, then that party may petition the IURC for the desired changes and bear the burden of proving that such changes are in the public interest; however, any such petition shall not be filed without the petitioner first attempting to obtain the agreement of the other party. Subject to the following sentence, anyone else seeking a change to these Cost Allocation Guidelines may also petition the IURC and would bear the burden of proving that the proposed changes are in the public interest. However, any such petition shall not be filed without the Utility and the OUCC first being notified and given a reasonable opportunity to consider the proposed change. The Commission may also make modifications to these Cost Allocation Guidelines on its own motion, after notice and hearing.

These Cost Allocation Guidelines should be read in conjunction with the "Affiliate Guidelines" developed by the OUCC and Utility and also approved by the Commission in Cause No. 42233 and GCA50S1. Subject only to the Settlement Agreement and ARP approved in GCA50 and Cause No. 42233, the Affiliate Guidelines and the Cost Allocation Guidelines govern all current and future affiliate relationships between the Utility and its Affiliates, with the limited exception that the Commission may approve an Affiliate contract that differs from these Affiliate Guidelines if the Utility files a petition requesting an exception from the Affiliate Guidelines and satisfies its burden to demonstrate that such contract is in the public interest considering all relevant factors, including, but not limited to, price of service and the impact on competition.

DEFINITIONS

See the definitions section of the Affiliate Guidelines for the definitions of certain terms used in the Affiliate Guidelines and the Cost Allocation Guidelines.

GUIDELINES

1. No Cross-Subsidies. The Utility shall not subsidize its Affiliates or its non-regulated operations.
2. The Utility shall maintain and utilize an accounting system and records that identify and appropriately allocate costs between the Utility and its Affiliates.
3. The Utility's costs for rate purposes shall reflect only those reasonable costs attributable to providing adequate and reliable service to its customers.
4. The Utility and all Affiliates that share corporate support and administrative services shall maintain documentation, such as organizational charts, accounting bulletins, procedure and work order manuals or other related documents, which describe how costs are allocated between regulated and non-regulated services or products.
5. Affiliates shall be charged an appropriate and reasonable allocation of all Shared Corporate Support Services costs incurred on their behalf. These costs include, but are not limited to, those associated with shared facilities and other corporate overheads.
6. To the maximum extent practicable, Shared Corporate Support Services costs should be accumulated and classified on a direct cost basis for each asset, service or product provided.
7. The Shared Corporate Support Services that cannot be directly assigned per item (6) above, should to the maximum extent possible be allocated to the Utility and its Affiliates and to the services or products to which they relate using relevant allocators which best reflect or consider the cost causative characteristics of the product/service being provided.
8. Where allocation/assignment pursuant to (6) and (7) is not practical, general allocation factors shall be utilized to allocate all remaining costs between the Utility and its Affiliates and between services and product lines ultimately provided by the Utility and its Affiliates.
9. The allocation of Capital Costs between the Utility and its Affiliates

(incurred in the provision of Shared Corporate Support Services) shall be based on the following:

- a. The cost of capital used for such allocations shall equal the Utility's current, weighted average cost of capital.
 - b. Depreciation shall be charged on a straight-line basis. Depreciation rates used for such allocations shall be consistent with the expected useful life of the asset(s) and in accordance with generally accepted accounting principles and regulatory accounting requirements, as applicable.
10. The Utility and its Affiliates shall maintain separate books and records, which shall be available for Commission inspection consistent with Indiana Law.
11. The OUCC and its agents shall have access to officers and employees and access to the books and records of the Utility and its Affiliates as reasonably necessary to ensure compliance with the Affiliate Guidelines, the Cost Allocation Guidelines and Title 8 of the Indiana Code. If disputes arise regarding the reasonableness of the timing or scope of requested access to Affiliate and Utility books and records, if not resolved by the parties, then such disputes may be presented to the Commission through use of an alternative dispute resolution process as agreed upon by the OUCC and Utility. During this process, the OUCC shall bear the burden of demonstrating why it needs certain books and records and the Utility shall bear the burden of demonstrating the unreasonableness of the OUCC's request. In seeking a resolution of access disputes, the parties agree that time is of the essence, and the intent of the parties is that the Commission's review of such disputes will be facilitated by the parties so that the review can be as expeditious as possible.
12. The cost assignment/allocation methodologies discussed herein are applicable to Shared Corporate Support Services. The Utility's procurement of all other goods, services, assets or other resources shall be on competitive terms, consistent with the public interest and in compliance with the Affiliate Guidelines and the Cost Allocation Guidelines.

AUDIT REQUIREMENTS

By December 31 of each year, the OUCC may select an independent auditor to perform a review and audit to ensure that the Utility has complied with these Cost Allocation Guidelines during its most recent fiscal year. In selecting the independent auditor, the OUCC will follow its normal state

procurement practices. OUCC staff members may assist the auditor. Any alleged violations of the Cost Allocation Guidelines shall be noted and explained in the auditor's report, a copy of which shall be provided to the Utility and the OUCC. The Utility shall have thirty (30) days following receipt of the auditor's report within which to respond to any alleged violations. The Utility agrees to make a contribution toward the auditor's costs/fees which shall not exceed \$25,000 in any twelve-month period.

**AFFILIATE AND COST ALLOCATION GUIDELINES FOR INDIANA GAS
COMPANY, INC. AND SOUTHERN INDIANA GAS AND ELECTRIC COMPANY**

INTRODUCTION

The OUCC and Indiana Gas Company, Inc. and/or Southern Indiana Gas and Electric Company ("Utility") (collectively "Parties") have negotiated in connection with Cause No. 41465 the following Affiliate Guidelines to govern the relationships between the Utility and its Affiliates. By agreement, the Guidelines have been modified in connection with Cause No. 37394GCA50S1 ("GCA50"). The Parties agree that these guidelines are intended to be enforced by the IURC, and they shall become effective upon their approval by the IURC. The OUCC and Utility may, through negotiation and agreement, jointly petition the IURC for modifications to these Affiliate Guidelines, in which case they would have the burden of proving any proposed change is in the public interest considering all relevant factors, including, but not limited to, price of service and the impact on competition. If either the OUCC or Utility desires changes to these Affiliate Guidelines and is unable to obtain agreement from the other party for such changes, then the party desiring changes may petition the IURC for the desired changes and bear the burden of proving that such changes are in the public interest. However, such petitions shall not be filed without first attempting to obtain the agreement of the other party. Subject to the following sentence, anyone else seeking a change to these Guidelines may also petition the IURC and would bear the burden of proving that the proposed changes are in the public interest. However, any such petition shall not be filed without the Utility and the OUCC first being notified and given a reasonable opportunity to consider the proposed change. The Commission may also make modifications to these Affiliate Guidelines on its own motion, after notice and hearing.

These Affiliate Guidelines should be read in conjunction with the "Cost Allocation Guidelines" developed by the OUCC and Utility and also approved by the Commission in Cause No. 41465. Subject through March 31, 2007 to the Settlement Agreement and ARP approved in GCA50 and Cause No. 42233, the Affiliate Guidelines and the Cost Allocation Guidelines govern all current and future affiliate relationships between the Utility and its Affiliates, with the limited exception that the Commission may approve an Affiliate contract that differs from these Guidelines if the Utility files a petition requesting an exception from the Guidelines and satisfies its burden to demonstrate that such contract is in the public interest considering all relevant factors, including, but not limited to, price of service and the impact on competition.

One purpose of these Affiliate Guidelines is to establish standards for procurement on competitive terms to govern the Utility's procurement of goods, services, assets and other utility resources. Such procurement "on competitive terms" (as defined herein) shall be done with the objective of obtaining the best terms available for the Utility and its customers. The only exception to these procurement standards is the provision of "shared corporate support and administrative services" such as corporate treasury services and human resources. These services may be shared with other companies/affiliates within the Vectren organization. The

pricing of those services to the Utility shall be based on cost and be in accordance with the Cost Allocation Guidelines. See the definitions section below for a complete definition of "shared corporate support and administrative services."

DEFINITIONS

The definitions below apply to terms used in the Affiliate Guidelines and the Cost Allocation Guidelines.

"Affiliate" "Affiliate" means a person that is an affiliated interest for purposes of I.C. 8-1-2-49 or that is otherwise found to be an "Affiliate" by the Commission or otherwise is an "Affiliate" under Indiana Law.

"Person" "Person" includes the following: (a) individual, (b) corporation, regardless of type or state or country of incorporation, (c) unincorporated association, (d) company, whether limited liability or otherwise, and (e) business trust, estate, partnership, trust, two (2) or more persons having a joint or common economic interest, and any other entity.

"Commission" "Commission" means the Indiana Utility Regulatory Commission.

"IURC" "IURC" means the Indiana Utility Regulatory Commission.

"OUCC" "OUCC" means the Indiana Office of Utility Consumer Counselor.

"Holding Company" "Holding Company" means the parent company, Vectren Corporation, or its successor in interest of Indiana Gas Company and/or Southern Indiana Gas and Electric Company.

"Competitive Terms" "Competitive Terms" means the best terms reasonably available in the competitive marketplace at that time (including the terms available from the Utility itself under efficient operation) giving due consideration to both price and non-price terms such as quality and reliability. If the Utility itself can provide the services at the lowest cost with comparable quality and reliability, then that cost shall be considered the "competitive terms."

"Shared Corporate Support and Administrative Services" - means the following types of functions/services that the Utility may share with other companies/affiliates within the Vectren organization: (1) accounting and corporate treasury services; (2) human resources; (3) information technology and communications services; (4) corporate directors and officers services; (5) legal services; (6) insurance and claims; (7) billing; (8) customer call center services; (9) facility and fleet management; and (10) environmental services. (See Specific Affiliate Guidelines 10, 12, and 15 related to "Shared Corporate Support and Administrative Services.")

"Capital Costs" "Capital Costs" means the costs associated with obtaining the financial capital required to provide physical assets such as office buildings, computers or office equipment.

"Non-Regulated" "Non-Regulated" means not regulated by the Indiana Utility Regulatory Commission (IURC). "Non-Regulated" also applies to products or services over which the IURC has declined its jurisdiction.

"Similarly Situated" "Similarly Situated" means having general characteristics in common such as belonging to the same rate class or operating in the same or similar industries. A utility affiliated gas or power marketer would, for example, be considered similarly situated to other non-affiliated gas or power marketers.

GENERAL AFFILIATE GUIDELINES

- A. No Cross-Subsidies.** The Utility shall not subsidize Affiliates or non-regulated activities.
- B. Separation of Regulated and Non-Regulated Operations.** The separation of the Utility's regulated operations from the Holding Company's non-regulated business operations and Affiliates is necessary to prevent potential cross-subsidies. To the maximum extent practicable, the Utility shall separate its regulated operations from its own, its Affiliates and its Holding Company's non-regulated operations. Instances where such separation does not exist must otherwise be in compliance with the Affiliate Guidelines and the Cost Allocation Guidelines.
- C. No Discrimination.** The Utility shall not discriminate in favor of or otherwise give preferential treatment to its Affiliates, its Affiliates' customers or the Utility's own non-regulated activities
- D. Comparability of Service.** The Utility shall provide comparable service to all similarly situated marketers, customers or other entities, regardless of affiliation.
- E. Procurement on Competitive Terms.** With the exception of "shared corporate support and administrative services" (defined above) the procurement of goods, services, assets and other resources by the Utility shall be on competitive terms, consistent with the public interest and in compliance with these Affiliate Guidelines and the Cost Allocation Guidelines. The Utility may procure services from an Affiliate but such procurement must be done on competitive terms (defined above). The Utility's procurement process shall also comply with General Guideline C above (i.e., No Discrimination). The pricing of "shared corporate support and administrative services" to the Utility shall be based on cost and be in accordance with the Cost Allocation Guidelines.

SPECIFIC AFFILIATE GUIDELINES

1. Affiliates shall be charged for all costs incurred on their behalf. These costs shall be appropriately and reasonably allocated and shall include, but not be limited to, those associated with shared facilities, general and administrative support services and other corporate overheads.
2. The Utility shall process all similar requests for service in the same manner and within the same reasonable time period for all similarly situated customers, marketers and other entities, regardless of affiliation.
3. The Utility shall not give preference to or discriminate in favor of its Affiliates, its Affiliates' customers or its own non-regulated activities in matters including, but not limited to, the allocation, assignment, release, or transfer of rights to intrastate or interstate capacity, use of Utility distribution facilities, storage on system, rights to storage off system, or in the sale of gas.
4. The Utility shall not condition or tie any agreement to provide Utility service to any agreement relating to a service to be provided by an Affiliate.
5. To the maximum extent practicable, Utility employees shall function separately and independently from employees of Affiliates and those engaged in non-regulated activities including, but not limited to, gas marketers, power marketers and other service providers.
6. The Utility may not, through tariff or otherwise, give any Affiliate or an Affiliate's customer or any non-regulated activity a preference or an advantage with respect to the transportation of gas including, but not limited to, the movement or delivery of gas on its distribution system, the administration of customer contracts, scheduling, nomination, balancing, metering, storage, standby service, curtailment policy, or billing/invoice disputes.
7. The Utility shall apply tariffs and their provisions and all other aspects of Utility service on a consistent and non-discriminatory basis to all similarly situated marketers, customers, and other entities regardless of affiliation.
8. Any discount or rebate for utility service offered by the Utility to an Affiliate or an Affiliate's customer shall be offered on a non-discriminatory basis to all similarly situated marketers, customers or other entities, regardless of affiliations. If the Utility waives a penalty or fee related to Utility service for an Affiliate or an Affiliate's customer, it shall waive such penalty or fee for similarly situated others on a non-discriminatory basis.
9. The Utility shall not give preference to or discriminate in favor of its Affiliates or its Affiliate's customers in its provision of information. This includes, without

limitation, information related to the sale or marketing of energy or energy services to existing or potential new customers and information related to the availability of transmission, distribution or storage capacity. Specific customer information shall be made available to affiliated or unaffiliated entities only upon consent of the customer or as otherwise provided by law or commission rules or orders, except that customer name and address information may be provided to energy marketers or energy service providers.

10. The Utility may share information technology and communications services with other companies/affiliates within the Vectren organization. However, such sharing of information technology and communications services shall not be done in a manner that violates Specific Guideline 9 above regarding the non-discriminatory provision of information. The utility shall take whatever steps are necessary to fulfill this requirement such as, for example, the implementation of electronic "firewalls" or other measures to control access to Utility information.
11. The Utility shall not speak on behalf of its Affiliates or give the appearance that it speaks on behalf of its Affiliates. The Utility's Affiliates shall not speak on behalf of the Utility or give the appearance that they speak on behalf of the Utility.
12. Customer call handling shall be performed on a non-discriminatory basis without respect to affiliations of the customer or affiliations of the customer's marketer or energy service provider. If a customer requests information about alternative sources of supply, the customer service representatives shall offer to provide a list of all alternative suppliers known to be serving customers in the same rate class as the customer making the inquiry, except those suppliers excluded by mutual agreement of the Utility and the OUCC. Such a list may include utility affiliates, but the utility customer service representatives shall not promote or endorse services offered by an affiliate. To ensure compliance with Specific Guidelines 9, 10, 11 and 12, the guidelines for handling of customer calls and information have been set out in writing and attached as Appendix A-1.
13. The Utility's Affiliates shall not trade upon, promote, or suggest that they receive preferential treatment as a result of affiliation with the Utility.
14. The Utility and its Affiliates shall not participate in joint advertising. An Affiliate may, however, reference the fact of its affiliation with the holding company. Such public references shall not: (a) make the Affiliate appear to be part of the Utility, or (b) suggest that the Affiliate or the Affiliate's customers will have any advantage as a result of the affiliation.
15. If the charges for Utility services are combined with charges for non-regulated energy services into a single bill, such a combined bill format will be made

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available on a non-discriminatory basis to non-affiliated entities that provide energy services in the Utility's service territory.

16. The Utility and its Affiliates shall maintain separate books and records, which shall be available for Commission inspection consistent with Indiana law.
17. The OUCC and its agents shall have access to officers and employees and access to the books and records of the Utility and its Affiliates as reasonably necessary to ensure compliance with these Affiliate Guidelines, the Cost Allocation Guidelines and Title 8 of the Indiana Code. If disputes arise between the OUCC and Utility regarding the reasonableness of the timing or scope of requested access to Affiliate and Utility books and records, if not resolved by the parties, then such disputes may be presented to the Commission through use of an alternative dispute resolution process as agreed upon by the OUCC and Utility. During this process, Utility shall bear the burden of demonstrating the unreasonableness of the OUCC's request. In seeking a resolution of access disputes, the parties agree that time is of the essence, and the intent of the parties is that the Commission's review of such disputes will be facilitated by the parties so that the review can be as expeditious as possible.
18. All complaints relating to these Affiliate Guidelines and the Cost Allocation Guidelines, whether written or verbal, shall be submitted to the general counsel of the Utility or the Utility's highest ranking legal employee ("general counsel"). The general counsel shall acknowledge to complainant such complaint within five (5) working days of receipt. The general counsel shall conduct a preliminary investigation and prepare a written statement of the complaint which shall contain the name of the complainant and a detailed factual report of the incident or incidents underlying the complaint, including all relevant dates, companies involved, employees involved, and the specific claim. The general counsel shall provide a copy of the written statement to the complainant. The general counsel shall communicate the results of the preliminary investigation to the complainant in writing within twenty (20) days after the complaint was received including a description of any course of action to be taken. In the event the Utility and the complainant are unable to resolve the complaint, the complainant may file a complaint with the Commission. Any complaint filed with the Commission before same was filed with the Utility under this section shall be held in abeyance while the procedures outlined here are followed. The general counsel shall keep a log of all complaints for a period of not less than three (3) years and shall keep such log available for inspection by the IURC, OUCC and complainant.
19. All transactions between the Utility and its Affiliates shall be in accordance with a written contract filed with the IURC pursuant to I.C. 8-1-2-49. The Utility shall maintain sufficient records of all such transactions for at least three (3) years so as to allow for a complete and thorough audit.

20. The Utility shall meet with the OUCC to review all proposed Affiliate contracts. Upon filing of Affiliate contracts with the IURC, copies of such contracts will be delivered to the OUCC. Affiliate contracts shall be governed by Indiana law and these Affiliate Guidelines and the Cost Allocation Guidelines. To the extent the Guidelines contain provisions or commitments that go beyond what would otherwise be required under Indiana law, the Guidelines shall control. The OUCC reserves its rights to challenge such contracts at any time.

PROCEDURES FOR FILING AFFILIATE CONTRACTS

All Affiliate contracts shall be filed with the IURC and be in conformance with these Guidelines, the Cost Allocation Guidelines and Indiana law. Such contracts shall be available for public inspection, except to the extent that information is protected from public disclosure under Indiana law. These Affiliate Guidelines in no way affect the IURC's duties and/or authority under Indiana law to *inter alia* investigate such contracts, hold public hearings related to such contracts and/or disapprove such contracts. These Affiliate Guidelines also in no way affect the OUCC's rights to *inter alia* initiate investigations of such contracts.

ANNUAL INFORMATIONAL FILING

The Utility shall file annually with the Commission and provide copies to the OUCC the following information concerning the Utility's Affiliates and its non-regulated activities.

1. The names and business addresses of the officers and directors of each Affiliate that has transacted any business with the Utility during the previous twelve (12) months. For each such Affiliate, the Utility shall also provide the following in its annual informational filing:
 - a. The Affiliate's name and a description of the Affiliate's primary line(s) of business and a description of the nature of the Affiliate's business with other non-affiliated entities.
 - b. A schedule detailing and summarizing the nature and dollar amounts of the transfers of assets, goods and services between the Utility and the Affiliate that took place during the applicable twelve-month period.
2. A listing of all contracts currently in effect between the Utility and Affiliate(s) indicating the nature of the transactions, the date the contract became effective and the contract's expiration date.
3. A corporate organization chart, which shows the parent holding company, the Utility, its Affiliates, and their relationships to one another.

4. A description of the method(s) used to identify, value, and record transfers of assets, goods and services between the Utility and its Affiliates.
5. A description of the method(s) used to allocate federal and state income tax expense, payments and refunds to the Utility and its Affiliates.
6. A description of sharing of personnel between the Utility and its Affiliates during the twelve-month period.
7. A log of complaints maintained by the Utility under section 18 of Specific Affiliate Guidelines.
8. A listing and description of all non-regulated activities engaged in by the Utility, including the amount of revenues and expenses generated by each such non-regulated activity.

These annual informational filings shall commence on the date thirty (30) days after the effective date of the Commission's approval of these Affiliate Guidelines, and shall repeat thereafter at the end of the Utility's fiscal year. These annual informational filings shall not serve or be interpreted as a pre-approval process.

**COST ALLOCATION GUIDELINES FOR INDIANA GAS
AND SOUTHERN INDIANA GAS AND ELECTRIC COMPANY**

INTRODUCTION

The OUCC and Indiana Gas Company, Inc. and Southern Indiana Gas and Electric Company ("Utility") (collectively "Parties") have negotiated in connection with Cause No. 41465 the following Cost Allocation Guidelines to govern the allocation of costs between the Utility and its Affiliates. By agreement, the Guidelines have been modified in connection with Cause No. 37394 GCA 50S1 ("GCA50"). The OUCC retains all of its rights and authority to dispute the reasonableness of and/or recovery of all Utility costs, including those to which these Cost Allocation Guidelines may be applicable. Mere allocation of costs under these guidelines does not predetermine the reasonableness of rate recovery of such costs. The Parties agree that these guidelines are intended to be enforced by the IURC, and they shall become effective upon their approval by the IURC. The OUCC and Utility may, through negotiation and agreement, jointly petition the IURC for modifications to these Cost Allocation Guidelines, in which case they would have the burden of proving any proposed change is in the public interest considering all relevant factors, including, but not limited to, price of service and the impact on competition. If either the OUCC or Utility desires changes to these Cost Allocation Guidelines and is unable to obtain agreement from the other party for such changes, then the party desiring changes may petition the IURC for the desired changes and bear the burden of proving that such changes are in the public interest. However, such petitions shall not be filed without first attempting to obtain the agreement of the other party. Subject to the following sentence, anyone else seeking a change to these Cost Allocation Guidelines may also petition the IURC and would bear the burden of proving that the proposed changes are in the public interest. However, any such petition shall not be filed without the Utility and the OUCC first being notified and given a reasonable opportunity to consider the proposed change. The Commission may also make modifications to these Cost Allocation Guidelines on its own motion, after notice and hearing.

These Cost Allocation Guidelines should be read in conjunction with the "Affiliate Guidelines" developed by the OUCC and Utility and also approved by the Commission in Cause No. 41465. Subject through March 31, 2007 to the Settlement Agreement and ARP approved in GCA50 and Cause No. 42233, the Affiliate Guidelines and the Cost Allocation Guidelines govern all current and future affiliate relationships between the Utility and its Affiliates, with the limited exception that the Commission may approve an Affiliate contract that differs from these Guidelines if the Utility files a petition requesting an exception from the Guidelines and satisfies its burden to demonstrate that such contract is in the public interest considering all relevant factors, including, but not limited to, price of service and the impact on competition.

The following Cost Allocation Guidelines govern the allocation of costs associated with "shared corporate support and administrative services" which have been defined in the definition section

of the Affiliate Guidelines and which may be shared with other companies/affiliates within the Vectren organization. By their nature, these costs are associated with functions and operations that are shared and not separate. The allocation methods should apply to those Utility Affiliates who share corporate support and administrative functions in order to prevent subsidization from the regulated Utility and ensure equitable cost sharing among the regulated Utility and its Affiliates. The pricing of "shared corporate support and administrative services" to the Utility shall be based on cost and be in accordance with these Cost Allocation Guidelines.

DEFINITIONS

See the definitions section of the Affiliate Guidelines for the definitions of terms used in the Affiliate Guidelines and the Cost Allocation Guidelines.

GUIDELINES

1. No Cross-Subsidies. The Utility shall not subsidize Affiliates or non-regulated activities.
2. The Utility shall maintain and utilize an accounting system and records that identify and appropriately allocate costs between the Utility and its Affiliates.
3. The Utility's costs for jurisdictional rate purposes shall reflect only those costs attributable to its jurisdictional customers.
4. The Utility and all Affiliates that share corporate support and administrative services shall maintain documentation including organizational charts, accounting bulletins, procedure and work order manuals or other related documents, which describe how costs are allocated between regulated and non-regulated services or products.
5. Affiliates shall be charged an appropriate and reasonable allocation of all shared corporate support and administrative costs incurred on their behalf. These costs include, but are not limited to, those associated with shared facilities and other corporate overheads.
6. To the maximum extent practicable, shared corporate support and administrative costs should be accumulated and classified on a direct cost basis for each asset, service or product provided.
7. The shared corporate support and administrative costs that cannot be directly assigned per item (6) above, should to the maximum extent possible be allocated to the Utility and its Affiliates and to the services or products to which they relate using relevant allocators which best reflect or consider the cost causative characteristics of the product/service being provided.

8. Where allocation/assignment pursuant to (6) and (7) is not practical, general allocation factors shall be utilized to allocate all remaining costs between the Utility and its Affiliates and between service and product lines ultimately provided by the Utility and its Affiliates.
9. The allocation of capital costs between the Utility and its Affiliates (incurred in the provision of "shared corporate support and administrative" services) shall be based on the following:
 - a. The cost of capital used for such allocations shall equal the Utility's weighted average cost of capital as last found by the Commission.
 - b. Depreciation shall be charged on a straight-line basis. Depreciation rates used for such allocations shall be consistent with the expected useful life of the asset(s) and in accordance with generally accepted accounting principles and regulatory accounting requirements, as applicable.
10. The Utility and its Affiliates shall maintain separate books and records, which shall be available for Commission inspection consistent with Indiana Law.
11. The OUCC and its agents shall have access to officers and employees and access to the books and records of the Utility and its Affiliates as reasonably necessary to ensure compliance with the Affiliate Guidelines, the Cost Allocation Guidelines and Title 8 of the Indiana Code. If disputes arise regarding the reasonableness of the timing or scope of requested access to Affiliate and Utility books and records, if not resolved by the parties, then such disputes may be presented to the Commission through use of an alternative dispute resolution process as agreed upon by the OUCC and Utility. During this process, Utility shall bear the burden of demonstrating the unreasonableness of the OUCC's request. In seeking a resolution of access disputes, the parties agree that time is of the essence, and the intent of the parties is that the Commission's review of such disputes will be facilitated by the parties so that the review can be as expeditious as possible.
12. The cost assignment/allocation methodologies discussed herein are applicable to shared corporate support and administrative services. The Utility's procurement of all other goods, services, assets or other resources shall be on competitive terms, consistent with the public interest and in compliance with the Affiliate Guidelines and the Cost Allocation Guidelines.

AUDIT REQUIREMENTS

Each year an independent auditor appointed by the OUCC shall do an audit. OUCC staff members may assist the auditor. The purpose of the audit shall be to ensure that the Utility complies with these Cost Allocation Guidelines. Any violations of the Cost Allocation Guidelines shall be noted and explained in the auditor's report, a copy of which shall be provided to the Utility, the Commission and the OUCC. Vectren shall annually contribute up to \$50,000 toward the auditor's costs/fees.

Appendix J

Consistent with and in furtherance of the spirit and intent of Article V of the Settlement Agreement and in particular, Section 5.3, the Parties and Signatory to the Settlement Agreement agree and acknowledge that alternative dispute resolution ("ADR") methods may provide useful tools to facilitate the interpretation and implementation of the Affiliate Guidelines which are appendices H and I of the Settlement. To that end, the Parties and Signatory agree that they may, by mutual agreement, proceed to utilize any of the ADR methods provided for in the Rules of Alternative Dispute Resolution as adopted by the Indiana Supreme Court, in the event of any dispute.

The Parties and Signatory further agree that negotiation may be the preferred ADR method although all are available for use. In no event, however, is any Party or Signatory compelled to utilize ADR in lieu of any other available remedy and the availability of ADR or this Appendix may not be raised as a defense in the nature of "failure to exhaust administrative remedies" in the event ADR is not utilized.

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Re The City of Indianapolis
Cause No. 37399-GCA84-S1

Indiana Utility Regulatory Commission
September 22, 2005

Before Hardy, Hadley, Landis, and Ziegner (all concurring), commissioners, and Divine, administrative law judge.

BY THE COMMISSION:

*1 On October 1, 2004, in accordance with Ind. Code 8-1-2-42, the Board of Directors for Utilities of the Department of Public Utilities of the City of Indianapolis, as Successor Trustee of a Public Charitable Trust, d/b/a Citizens Gas & Coke Utility ('Petitioner,' 'Citizens,' or the 'Utility') filed with the Indiana Utility Regulatory Commission ('Commission') its verified Petition in Cause No. 37399-GCA84 for approval of a Gas Cost Adjustment ('GCA') to be applicable during the months of December 2004, and January and February 2005. In that GCA proceeding, Citizens also proposed that a Gas Cost Incentive Mechanism ('GCIM') credit of \$252,410, attributable to certain February and March 2003 gas exchange transactions (the 'Gas Exchange Transactions'), be distributed to customers through the GCA in accordance with the terms of a Gas Exchange Letter Agreement (the 'Gas Exchange Agreement') between Citizens and ProLiance Energy, LLC ('ProLiance') dated July 29, 2004.

On November 5, 2004, the Indiana Office of Utility Consumer Counselor ('Public' or 'OUCC') filed its Motion to Establish Subdocket and Prehearing Conference for Investigation of Gas Exchange Transactions between Citizens Gas & Coke Utility and ProLiance Energy, LLC Pursuant to Gas Exchange Agreement Dated July 29, 2004. In its Motion, the OUCC stated that the Gas Exchange Agreement, as well as the proper amount of any savings that should be attributed to Citizens' customers deserves review and scrutiny in a separate proceeding. The Commission granted the OUCC's Motion on January 20, 2005, and established this subdocket proceeding.

On February 14, 2005, Citizens Industrial Group ('Industrial Group'), an ad hoc group of Citizens' industrial customers, filed a Petition to Intervene. The Commission granted the Industrial Group's Petition to Intervene during the Prehearing Conference held on February 17, 2005. On March 2, 2005, the Commission issued a Prehearing Conference Order setting forth a procedural schedule in this Cause.

Citizens prefiled the direct testimony and exhibits of LaTona S. Prentice and Lindsay C. Lindgren on December 21, 2004. On February 25, 2005, the OUCC prefiled the direct testimony and exhibits of Tyler E. Bolinger and Jerome D. Mierzwa. On

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the same day, the Industrial Group prefiled the direct testimony and exhibits of Nicholas Phillips, Jr. The Industrial Group contemporaneously filed a Motion requesting that the Commission take administrative notice of the June 4, 2002 Settlement Agreement and July 24, 2002 Order in Consolidated Cause Nos. 37394-GCA50S1, 37399-GCA50S1 and 42233 ('GCA50').

On March 15, 2005, Citizens prefiled the rebuttal testimony and exhibits of Ms. Prentice and Mr. Lindgren. On that same date, Citizens also filed an Objection and Motion to Strike Certain Testimony Related to Settlement Negotiations ('Objection and Motion to Strike'). The OUCC filed its Response to Citizens' Objection and Motion to Strike on April 6, 2005, and Citizens filed a Reply on April 11, 2005.

*2 Pursuant to notice published as required by law, a public Evidentiary Hearing was convened on April 13, 2005, at 9:30 A.M. in the Conference Center, Room No. 32, Indiana Government Center South, 302 West Washington Street, Indianapolis, Indiana and continued to the close of the record on April 14, 2005. Citizens, the OUCC and the Industrial Group participated in the hearing. No members of the general public appeared.

At the outset of the Evidentiary Hearing, the Presiding Officers granted the Industrial Group's Motion to take administrative notice of the GCA50 Settlement Agreement and Order. The Presiding Officers also granted, in part, Citizens' Objection and Motion to Strike. The Presiding Officers found that two sentences in the OUCC's prefiled testimony constituted evidence of conduct or statements made in compromise negotiations, and these two sentences were not admitted into the record.

Based upon the applicable law and the evidence presented herein, the Commission now finds:

1. Commission Notice and Jurisdiction. Due legal and timely notice of the commencement of the public hearing in this Cause was given and published by the Commission as required by law. Citizens operates a municipal gas utility and, as such, is subject to the jurisdiction of this Commission as provided by the laws of the State of Indiana, including certain sections of the Public Service Commission Act, as amended. The provisions of said Act authorize the Commission to act in this proceeding. The Commission, therefore, has jurisdiction over the parties and the subject matter herein.

2. Characteristics of Citizens. Citizens' principal office is located at 2020 North Meridian Street, Indianapolis, Indiana. It is engaged in rendering natural gas utility service to the public within the State of Indiana and owns, operates, manages, and controls plant and equipment used for the distribution and furnishing of such service.

3. History of the Gas Exchange Transactions and the Gas Exchange Agreement.

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A. The Gas Exchange Transactions. Petitioner's witness, Lindsey C. Lindgren, Citizens' Vice President of Gas Operations and a member of the Board of Directors of ProLiance, described the origin of the Gas Exchange Transactions. Beginning in early 2003, Citizens discussed with its gas supplier, ProLiance, the possibility of diverting to alternative buyers, flowing pipeline deliveries of gas which otherwise would be delivered to Citizens. Mr. Lindgren testified that his role in these negotiations between Citizens and ProLiance was to represent the interests of Citizens and Citizens' customers. To make up for the diverted gas deliveries, Citizens would use its company-owned storage facilities (either its liquefied natural gas ('LNG') facilities or underground storage ('UGS') facilities located in Greene County) for system supply purposes. Under certain circumstances pipeline deliveries would be diverted in winter heating months, when the price of gas is high and ProLiance would reimburse Citizens, in kind, during the summer months for any gas withdrawn to make up for the diversions. According to Mr. Lindgren, the proposed gas exchange transactions would ultimately result in no impact to the price of gas in Citizens' storage. The initial transaction was discussed at a meeting between Citizens and ProLiance during the unusually high gas price period of late February, 2003. Mr. Lindgren indicated that Citizens and ProLiance believed the potential existed to substitute Citizens' system storage gas for flowing supply for a period of approximately one week based on the market, system demand and then-existing inventory levels.

*3 Mr. Lindgren stated that shortly after identifying the opportunity to enter into gas exchange transactions, Citizens representatives met with representatives from the OUCC. The initial Gas Exchange Transaction occurred on February 25, 2003. The first meeting between Citizens and OUCC representatives occurred one day later, on February 26, 2003. At the hearing, LaTona S. Prentice, Citizens' Director of Regulatory Affairs, indicated there was a telephone call to the OUCC on the subject of gas exchange transactions prior to this meeting. Mr. Lindgren described this meeting as an overview of the gas exchange transaction, including a high level discussion on how the exchange transaction would work, when it would occur, and how Citizens proposed to share the benefits with customers through a GCIM calculation. Citizens believed timing was crucial, and indicated that it intended to complete the initial exchange transactions and subsequently work out details regarding how the value of the transactions would be shared with customers.

Citizens and the OUCC presented divergent testimony regarding the OUCC's response to the proposed gas exchange transactions. Mr. Lindgren recalls the OUCC being generally supportive of the proposed gas exchange transactions and that the OUCC 'seemed to agree the proposed exchange transaction likely would create a benefit for Citizens Gas' customers' (Petitioner's Exhibit LCL, page 5).

However, OUCC witness Bolinger asserted that the OUCC made several points clear to Citizens at the February 26, 2003 meeting. Mr. Bolinger recalled telling Citizens that off-system sales are not within the scope of the GCIM and that the OUCC was not authorized to approve such initiatives on the basis of informal meetings.

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Mr. Bolinger indicated to Citizens that the OUCC had neither the desire nor the authority to approve such strategies or initiatives through informal meetings. Furthermore, any off-system sales program would be viewed within the framework of the Indiana GCA and the GCA50 Settlement. Mr. Bolinger also recalled explaining to Citizens that the Commission and the other Consumer Parties to the GCA50 Settlement would be interested in these matters and likely view them under the GCA50 framework.

Mr. Lindgren does not recall Mr. Bolinger making those statements, but 'remember[s] the OUCC's representatives indicating that they wanted to review any written agreement between Citizens and ProLiance, as well as any documentation for completed transactions, before considering how the gas exchange benefits should be shared with customers' (Petitioner's Exhibit LCL-R, page 3). Mr. Lindgren also recalls the OUCC emphasized that Citizens should be sure the gas exchange transactions did not subject Citizens' customers to any risks or jeopardize Citizens' gas supply.

According to Mr. Lindgren, Citizens and ProLiance identified a one-week 'window of opportunity' to complete the gas exchange transactions. Because of this short window of opportunity, they did not enter into a formal written agreement prior to completing the transactions. Citizens and ProLiance completed the initial Gas Exchange Transaction on February 25, 2003. Four additional transactions were completed on March 1st , 2nd , 3rd and 6th , 2003.

***4 B. The Gas Exchange Agreement.** Citizens and ProLiance began negotiating a formal written agreement following the completion of the February/March 2003 Gas Exchange Transactions. According to Petitioner's witness, LaTona S. Prentice, by September 4, 2003, Citizens and ProLiance had negotiated the terms of the Gas Exchange Agreement, and Citizens provided an unexecuted copy to the OUCC for its review and comment. Ms. Prentice stated that Citizens and the OUCC met on several occasions thereafter in an attempt to reach an agreement with respect to the sharing of benefits and other terms of the Gas Exchange Agreement, but were unable to do so.

On July 29, 2004, Citizens and ProLiance executed the Gas Exchange Agreement. The Gas Exchange Agreement provided that Citizens may, at its sole discretion, allow ProLiance to divert flowing pipeline deliveries of gas, which otherwise would be delivered to Citizens, to alternative buyers. In a 'backstop' provision, ProLiance guaranteed to replace any diverted gas at the request of Citizens, to the extent exchange transactions 'cause an operational lowering of Citizens' daily deliverability capabilities from its underground storage.'

The Gas Exchange Agreement provided that the 'net value' derived from each 'exchange transaction' will be recognized by Citizens and its customers through a credit to Citizens' August bill from ProLiance, and 'will be shared with customers according to the GCIM process.' In general, the 'net value' to be shared with cus-

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tomers was the gross value of the transaction, less operation and maintenance expenses and the cost of the gas which was to be physically returned to Citizens. The gross value of the transaction was determined by multiplying the volume of the diverted gas by the appropriate price published in Gas Daily for the applicable day. The cost of the returned gas was to be based on NYMEX futures prices.

The 'net value' of exchange transactions was to be 'shared with customers according to the GCIM process.' The GCIM was agreed to as part of the GCA50 Settlement Agreement and contains a revenue sharing mechanism between Citizens and its customers for certain gas procurement efforts. The GCIM further provides that Citizens may at its discretion pass its share of the risks and rewards for gas acquisition performance to ProLiance.

In general, under the GCIM, the percentage of the 'net value' of the exchange transactions to be distributed to customers varies depending upon how significantly the transactions reduce Citizens' monthly commodity purchase costs below the 'benchmark price.' If the transactions result in a net reduction in commodity purchase costs of less than 2% below the 'benchmark,' 70% is distributed to customers and Citizens may retain 30% of the savings. If the net reduction is between 2% and 4% below the 'benchmark,' the savings are split evenly between customers and Citizens. If the net reduction to commodity purchase costs is greater than 4% below the 'benchmark,' 30% is distributed to customers and Citizens may retain 70% of the savings.

*5 It was intended that the Gas Exchange Agreement cover the transactions completed in February/March 2003, as well as any future exchange transactions that may occur between the parties through December 31, 2005. The Gas Exchange Agreement provides that it will continue in effect after December 31, 2005, on a month-to-month basis unless one of the parties terminates it.

On September 1, 2004, Citizens filed the Gas Exchange Agreement with the Commission pursuant to the terms of the Commission's Order in GCA50. Citizens then included a \$252,410 credit to gas costs in Cause No. 37399-GCA84, representing the customers' share of the 'net value' of the February/March 2003 exchange transactions (i.e., 30% of the total net value of \$841,368).

4. Citizens' Case-in-Chief. Citizens presented evidence showing that the February/March 2003 Gas Exchange Transactions produced a \$252,410 benefit for its customers. Citizens' witness Lindgren testified that the Utility's 'goal in entering into the Agreement and in completing the initial exchange transactions was to provide value for its customers.' (Petitioner's Exhibit LCL at 7.) Citizens' witness Prentice stated that, in fact, 57% of the monies passed back to the Utility's customers over the 23 months the GCIM process has been in place were earned in the February/March 2003 Gas Exchange Transactions.

Ms. Prentice discussed why she believes it is appropriate for the net value of

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the transactions to be shared with customers using the percentage split mechanism prescribed under the GCIM process. The GCIM process was agreed upon by the parties in GCA50 in order to provide incentives for ProLiance to beat the GCIM benchmark. Ms. Prentice stated that in her opinion, the exchange transactions are precisely the type of transactions intended to be encouraged under the GCIM procedure, since they are a mechanism developed by ProLiance, in association with Citizens, as a means to 'beat the GCIM benchmark.'

Citizens also presented evidence regarding the importance of ProLiance's participation in the transactions. Mr. Lindgren testified that ProLiance has a broad network of contacts and relationships in the industry to facilitate the sale of the diverted gas. ProLiance also has the expertise, portfolio and resources necessary to implement the transactions. Resources required to implement exchange transactions include: software and system support, risk management tools and pipeline capacity. Mr. Lindgren stated that Citizens no longer employs gas acquisition and trading staff.

Mr. Lindgren also noted that ProLiance assumes all risks associated with the exchange transactions. Under the backstop provision of the Gas Exchange Agreement, ProLiance guarantees that any gas used in exchange transactions will be replaced with no cost impact to Citizens and its customers. Mr. Lindgren testified that in order for Citizens to capitalize on exchange opportunities without assistance from ProLiance, Citizens would have to bear the risk that the replacement cost of the exchanged gas would be the same or less than the cost of that gas. This is a risk the Utility would not be willing to bear.

*6 Mr. Lindgren testified that based on the important role ProLiance played in completing the Gas Exchange Transactions, he believed it was appropriate for Citizens to share its portion of the value of the exchange transactions with ProLiance. Without compensation there would be no incentive for ProLiance to bear the risk and incur the operating costs associated with the transactions.

Citizens also presented evidence that it would not have been possible for it to have arranged the exchange transactions with any other marketer. As Citizens' portfolio administrator, ProLiance administers the Utility's gas portfolio and supply plan. Mr. Lindgren indicated that any exchange transaction necessarily results in a change to Citizens' supply plan for a certain period. Moreover, the initial exchange transactions in February/March 2003 were carried out within a short 'window of opportunity,' making it impossible to seek and obtain bids from alternative providers.

5. OUCC's Case-in-Chief. The OUCC presented the testimony of Tyler E. Bolinger and Jerome D. Mierzwa. Mr. Bolinger is the OUCC's Director of Natural Gas. Mr. Mierzwa is a Principal and Vice President with Exeter Associates, Inc. (Exeter), located in Columbia, Maryland. Exeter specializes in providing public utility-related consulting services.

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Mr. Bolinger testified that the Gas Exchange Agreement is not in the best interest of Citizens' customers. Mr. Bolinger recommended disapproval of the Gas Exchange Agreement, and that Citizens be ordered to conduct no future off-system sales or gas exchanges under that agreement. Mr. Bolinger further testified that the Gas Exchange Agreement violates the GCIM agreement and the Affiliate Guidelines established in the GCA50 Settlement Agreement. He further testified that there is a serious lack of transparency in the accounting for the actual costs and benefits of the transactions.

Mr. Bolinger explained that the GCA50 Settlement Agreement established the GCIM as part of a comprehensive settlement on gas supply issues. The GCIM consists of an introduction and three sections: (I) GCIM Commodity Purchases; (II) Price Volatility Mitigation Program (PVMP); and (III) Additional Provisions. Mr. Bolinger testified that no section of the GCIM addresses the treatment of off-system sales or gas exchanges. In fact, the terms 'off-system sales' and 'gas exchange' do not exist in the GCIM. Mr. Bolinger testified that this is not an oversight.

According to Mr. Bolinger, the Consumer Parties in GCA50 did not intend to provide incentives for off-system sales in the GCIM. Mr. Bolinger testified that if the Consumer Parties had intended to accommodate off-system sales in the GCIM, then the GCIM would have included language describing such intentions, and he further contended that Citizens' attempt to overlay an off-system sales program on the GCIM is a unilateral attempt to amend the GCIM. Mr. Bolinger further testified '[w]hen the Parties had off-system sales in mind, they explicitly provided for them and stated how the proceeds would be shared. No such provisions were made for incentives to promote gas exchanges' (Public's Exhibit No. 1, page 14).

*7 Mr. Bolinger testified that the correct interpretation of Section I of the GCIM is critical to the evaluation of the Gas Exchange Agreement. According to Mr. Bolinger, Section I applies to non-hedged, monthly and daily commodity purchases and specifies a process for comparing the 'actual natural gas commodity purchase dollars' to the 'Benchmark dollars' every month. He further testified that the 'Benchmark dollars' provide a performance benchmark, based on published price indices, and if the 'actual natural gas commodity purchase dollars' are less than the 'Benchmark dollars,' then the utility and ratepayers share the savings according to the sharing ranges outlined in Section I.

Mr. Bolinger testified that Section I of the GCIM rewards (or penalizes) superior (or inferior) performance at purchasing monthly and daily commodity supplies for GCA customers. ProLiance purchases those supplies for Citizens as its agent. Mr. Bolinger contended that Section I is narrow in scope; it only applies to non-hedged monthly and daily commodity purchases. He also stated that Section I is fairly stringent; it provides rewards only when commodity is acquired at a cost below published benchmarks. According to Mr. Bolinger, it is difficult to earn rewards (or be penalized) under Section I of the GCIM, and earning rewards requires

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the actual purchase of commodity at a price more favorable than published benchmarks.

Mr. Bolinger testified that the Gas Exchange Agreement diverges from the intentions of the GCIM. He stated that the Gas Exchange Agreement 'treats gas exchange net proceeds as if they were a reduction to the 'actual natural gas commodity purchase dollars' in a given month (August per the Agreement)' (Id., page 11, emphasis in text). Mr. Bolinger testified that Citizens' proposal is contrived to allow ProLiance to keep the lion's share of gas exchange proceeds. He stated that Section I of the GCIM provides no mechanism for sharing the proceeds of gas exchanges, and it certainly does not permit treating February or March gas exchange proceeds as if they were a reduction to actual natural gas commodity purchase dollars in August. In support of his position that off-system sales of commodity were not intended to be encompassed under the GCIM, Mr. Bolinger testified that the GCA50 Settlement Agreement includes a specific incentive mechanism for unused pipeline capacity.

Mr. Bolinger testified that in August 2003, ProLiance achieved a savings of \$187.86 as commodity purchasing agent for Citizens which, under the plain language and normal operation of the GCIM, would make ProLiance eligible for a reward equal to 30% of that savings, or about \$56.00. According to Mr. Bolinger, Citizens and ProLiance have executed a Gas Exchange Agreement that gives ProLiance a \$588,958 reward as if ProLiance had reduced actual natural gas commodity purchase dollars in August 2003 by \$841,368, which supposedly is the 'net value to share' from the gas exchanges in February and March 2003.

*8 Mr. Bolinger stated the following language in Section I of the GCIM requires the actual natural gas commodity purchase dollars to provide for a reasonable comparison to published price benchmarks: 'The calculation of the actual commodity costs shall include all relevant commodity costs and provide for a fair and reasonable comparison to published benchmarks.'

Mr. Bolinger testified that a ProLiance work paper attached to his testimony appears to provide such a reasonable comparison for August 2003. He stated that ProLiance's actual cost of commodity purchases for Citizens under Section I of the GCIM was within \$200.00 of the Benchmark, which is a roughly break even performance.

In contrast, Mr. Bolinger asserted, the Gas Exchange Agreement treats net gas exchange proceeds from February and March 2003 as if they were reductions to the August 2003 actual commodity purchase dollars for GCIM purposes. This proposal gives ProLiance a 70% share of the net proceeds. The deduction from actual August 2003 commodity costs of net proceeds from February and March gas exchange transactions completely invalidates any comparison to August 2003 published benchmarks. Mr. Bolinger testified that this violates the explicit provision that the actual commodity costs provide for a fair and reasonable comparison to published benchmarks.

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Mr. Bolinger testified that the Gas Exchange Agreement also violates certain Affiliate Guidelines approved in the GCA50 Settlement Agreement. The Guidelines prohibit preferential treatment of affiliates (General Affiliate Guideline C). The Guidelines also require procurement on competitive terms (General Affiliate Guideline E). Specific Affiliate Guidelines Nos. 3 & 6 prohibit preferential access to utility storage capacity. Articles III & IV of the GCA50 Settlement Agreement address the Affiliate Guidelines and Competition. According to Mr. Bolinger, the Parties to the GCA50 Settlement Agreement made a commitment to a healthy competitive environment and, accordingly, enforcement of the Affiliate Guidelines is critical.

Mr. Bolinger explained that under the Gas Exchange Agreement, Citizens will utilize its on-system storage resources in a manner highly beneficial to ProLiance, with ProLiance receiving up to 70% of the net proceeds from gas exchanges. He stated that these highly profitable opportunities -- made possible by utility resources -- are only available to ProLiance and will not promote the healthy competitive environment envisioned in Article IV of the GCA50 Settlement Agreement.

Mr. Bolinger recommended that the Commission find the Gas Exchange Agreement in violation of Citizens' Affiliate Guidelines. Mr. Bolinger testified that Citizens is wrong in its assertion that gas exchange transactions are eligible for incentives under the GCIM; that a straight-forward reading of the GCIM reveals no language that even suggests off-system sales or gas exchanges are within the GCIM's scope. Consequently, since the Gas Exchange Transactions are not encompassed under the GCIM, Mr. Bolinger testified that the Gas Exchange Agreement violates the Affiliate Guidelines prohibition of preferential treatment of affiliates and access to utility storage capacity.

*9 Mr. Mierzwa testified that the Gas Exchange Agreement addresses transactions wherein flowing pipeline gas supplies initially destined for Citizens were diverted by ProLiance and sold to a third party (off-system sale). Gas withdrawn from Citizens' UGS or LNG storage facilities was used to replace the diverted flowing gas supplies. ProLiance later reimbursed Citizens in kind for the gas withdrawn from storage. Such transactions would be contemplated when the diverted gas supplies can be sold at a price which exceeds the sum of the price of replacement supplies plus any incremental costs associated with the transactions.

Mr. Mierzwa explained that Citizens and ProLiance had engaged in exchange transactions prior to the execution of the Gas Exchange Agreement. More specifically, Citizens and ProLiance diverted 214,000 Dth of gas to third parties in late February 2003 and early March 2003. The diverted gas supplies were returned to Citizens in April and May 2003. Mr. Mierzwa stated that Citizens is proposing to retroactively apply the terms and conditions of the July 29, 2004 Gas Exchange Agreement to the February/March 2003 Gas Exchange Transactions. Under the Gas Exchange Agreement, a gross value for each transaction is determined from which any related operation and maintenance (O&M) costs and the cost of replacement gas are deduc-

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ted. The gross value serves as a proxy for the price ProLiance is able to sell the diverted supplies. The gross value is determined by multiplying the diverted quantity by a published index gas price applicable for the interstate pipeline utilized to deliver the diverted gas to the third party. The potential delivering pipelines are Panhandle Eastern and Texas Gas. For Panhandle, a Texas/Oklahoma index price is utilized and for Texas Gas, a Louisiana Onshore South index price is utilized.

Mr. Mierzwa testified that if the diverted gas supplies are replaced by gas withdrawn from Citizens' LNG facilities, the associated O&M costs are \$1.75 per Dth. If the transaction requires additional withdrawals from Citizens' UGS facilities, a \$0.15 per Dth O&M cost is deducted. The cost of the gas returned is based on the average of the closing NYMEX prices on the day of each exchange transaction for the following June, July and August.

Mr. Mierzwa explained that Citizens proposed that the proceeds calculated for each exchange transaction be shared with ratepayers pursuant to Citizens' GCIM. Citizens is rewarded under the GCIM if it is able to purchase gas at less than market index prices on a monthly basis. Because ProLiance is the entity (or agent) which actually purchases gas for Citizens under the terms of the GCIM, Citizens is authorized to, and does pass its reward under the GCIM on to ProLiance. The reward is based on the magnitude of the difference between Citizens' actual commodity gas cost and a gas cost benchmark based on market index prices. The Gas Exchange Agreement provides that the reward proceeds calculated for exchange transactions will be included in the GCIM in August of the subsequent year.

***10** Mr. Mierzwa testified that the gross value calculation will not always serve as a reasonable proxy for the revenues realized from each exchange. This is because under the Gas Exchange Agreement, an upstream index location is utilized as a proxy for the revenues generated by a specific transaction. He stated it would generally be expected that the diverted supplies would be delivered to a downstream location, geographically near Citizens. In such instances, diverted supplies would be expected to generate revenues in excess of the gross value which is based on upstream index prices. According to Mr. Mierzwa, this is because there is a locational value to gas. Diverted supplies available at downstream locations utilize interstate pipeline capacity to effectuate deliveries, and this capacity has value which would be reflected in the price paid to obtain the diverted supplies. The gross value calculation included in the Gas Exchange Agreement assigns no value to this capacity. The value of the capacity required to transport gas from the upstream index location to the downstream point of sale is reflected in the capacity release markets and basis differentials which exist between the upstream and downstream locations. Mr. Mierzwa testified that had Citizens sought competitive bids for the Gas Exchange Transactions, those bids would have reflected the value of the capacity utilized to effectuate the transactions.

Mr. Mierzwa testified that exchange transactions may increase gas costs to Cit-

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izens' customers. The Gas Exchange Agreement provides ProLiance strong incentives to engage in exchange transactions and market participants generally respond to incentives. Thus, the Gas Exchange Agreement may encourage ProLiance to engage in transactions that are inconsistent with the minimization of gas costs for Citizens' sales customers.

Mr. Mierzwa testified that in March 2003, Citizens purchased 1,332,922 Dth of flowing gas at an average 'first of month' (FOM) price of \$9.10 per Dth. This gas began flowing on the first of the month, and flowed on each day during the month. During the early portion of this month, Citizens participated in a number of Gas Exchange Transactions. The price of the gas in Citizens' LNG and UGS storage facilities, which was withdrawn and utilized to support the exchange transactions and replace the diverted gas supplies, was well below \$4.00 per Dth. Mr. Mierzwa saw no justification for why the gas in Citizens' storage facilities could not have been used to displace a portion of the gas that Citizens purchased at \$9.10 per Dth. Mr. Mierzwa recommended that unless Citizens can justify the purchase of \$9.10 per Dth gas when its stored gas supplies costing less than \$4.00 per Dth were available, the additional incremental costs should not be the responsibility of Citizens' sales customers. According to Mr. Mierzwa, if the purchase of \$9.10 per Dth gas cannot be justified, sales customers were adversely affected by the March 2003 exchange transactions and an adjustment of \$960,995 is appropriate.

*11 In an October 29, 2004 letter to the OUCC, Mr. Mierzwa asserted that there was no need for ProLiance to be involved in the type of service contemplated under the Gas Exchange Agreement. Citizens' witness, Mr. Lindgren, addressed that assertion in his direct testimony. Mr. Mierzwa referred to Mr. Lindgren's direct testimony that any exchange transaction necessarily results in a change to Citizens' supply plan and, therefore, it makes sense that exchange transactions be incorporated into Citizens' supply plan. He also referred to Mr. Lindgren's testimony that since ProLiance administers Citizens' supply, it is necessary for ProLiance to be involved. However, according to Mr. Mierzwa, Mr. Lindgren's testimony missed the point of the October 29, 2004 letter, which questioned why ProLiance merits a reward from the exchange transactions.

Mr. Mierzwa stated that under the current supply planning process, Citizens develops an estimate of its natural gas supply requirements for an upcoming period (daily, monthly, etc.). Citizens then submits its requirements to ProLiance, which develops a recommended supply plan. Citizens then reviews ProLiance's recommended plan and either approves or modifies the supply plan. Mr. Mierzwa believes that nothing prevents Citizens from modifying a supply plan to incorporate exchange transactions without input from ProLiance.

Mr. Mierzwa disputed Mr. Lindgren's other reasons for thinking it is necessary for ProLiance to be involved in the exchange transactions. Mr. Lindgren testified that ProLiance has a broad network of contacts and relationships in the industry to facilitate the sale of diverted gas. Mr. Lindgren also claimed that ProLiance

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has the expertise, resources and portfolio necessary to implement exchange transactions, and that Citizens no longer employs the gas acquisition and trading staff necessary to perform exchange transactions.

Mr. Mierzwa testified that Citizens is well aware, or should be, of other industry participants which would have been interested in participating in the exchange transactions had Citizens solicited alternative proposals. If Citizens solicited the interest of other parties, then it would have been able to ensure that exchange transaction proceeds were maximized for ratepayers. In addition, the other parties would have been able to assist Citizens in making the arrangements necessary to effect the transactions, since Citizens no longer employs gas acquisition and trading personnel. Mr. Mierzwa stated that based on the latest information available, ProLiance isn't even ranked as one of the top 20 marketers in North America. According to Mr. Mierzwa, it was unreasonable for Citizens to discriminate in favor of its affiliate when negotiating the exchange transactions when many potential alternatives existed.

Mr. Mierzwa also found it troubling that a major gas utility no longer employs personnel with gas acquisition or trading experience. Mr. Mierzwa believes this fact calls into question Citizens' ability to oversee ProLiance's performance under the contract by which ProLiance supplies gas to Citizens.

***12** Mr. Mierzwa disputed Mr. Lindgren's claim that ProLiance assumes all of the risks associated with the exchange transactions, and that this is a needed function. Mr. Mierzwa testified that ProLiance assumes little or no risk under the Gas Exchange Agreement. According to Mr. Mierzwa, the price at which the gas will be sold (or assumed to be sold) is known with relative certainty, as are the related O&M costs and the cost assigned to the replacement supplies. Therefore, based on revealed history, the magnitude of the proceeds of the exchange transactions will be such that they will significantly protect against any deviations from expected prices and costs.

Mr. Mierzwa also disagreed with Mr. Lindgren's claim that in order for Citizens to capitalize upon exchange opportunities without the assistance of ProLiance, Citizens would have to bear the risk that the replacement cost of the exchange gas would be the same or less. According to Mr. Lindgren, Citizens would not be willing to bear that risk. Mr. Mierzwa testified that this risk can be eliminated fairly easily by locking in a fixed price for the replacement gas at the time of an exchange transaction. Mr. Mierzwa asserted that Citizens currently purchases a significant percentage of its gas supplies at fixed prices, and if Citizens engaged in the exchange transactions with an entity other than ProLiance, that other entity could have likely secured the fixed price gas on Citizens' behalf.

Mr. Mierzwa challenged Mr. Lindgren's claim that Citizens had no time to do a competitive solicitation for the exchange transaction. Mr. Mierzwa testified that other interested participants in the gas industry engage in such transactions on a

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daily basis. Therefore, Mr. Mierzwa concluded there was time for Citizens to contact and solicit bids from other parties.

Mr. Mierzwa disputed Mr. Lindgren's emphasis on the backstop provision in the Gas Exchange Agreement. The backstop provision provides that if exchange transactions directly cause an operational lowering of Citizens' daily deliverability capabilities from underground storage, ProLiance will return the exchange gas earlier than the anticipated June/July/August period. Mr. Mierzwa found no indication that the February/March 2003 exchange transactions caused a lowering of Citizens' daily delivery capabilities and, therefore, was an important consideration in deciding whether to pursue the exchange transactions. Moreover, lowering of daily delivery capabilities from storage would generally be a significant concern in January or early February, when design peak day conditions are most likely to occur. According to Mr. Mierzwa, if an exchange transaction did cause a lowering of delivery capabilities in January, for example, returning that gas earlier, in April, would provide no benefit.

Mr. Mierzwa also disagreed with Mr. Lindgren's claim that absent the Gas Exchange Agreement, nearly 60 percent of the benefits that have been passed back to customers through the GCIM would not have existed, and thus the Gas Exchange Agreement is in the public interest. Mr. Mierzwa found that Citizens has wrongly determined that exchange transaction proceeds should be considered a component of the GCIM. Exchange transaction proceeds totaled \$841,368. Because Citizens flowed these proceeds through the GCIM, GCA customer share of the proceeds was only \$252,410. Mr. Mierzwa asserted that exchange transaction proceeds should not be flowed through the GCIM because Citizens, through ProLiance, did not acquire gas at a cost below the benchmarks established under the GCIM.

***13** Mr. Mierzwa testified that if the Commission accepts Citizens' position and finds that exchange transaction proceeds should flow through the GCIM, then the proceeds should be reflected in actual costs in the month in which the diversion occurs. By reflecting the exchange proceeds in the GCIM in August 2003, ProLiance retained 70 percent of the benefit. By more properly reflecting the exchange proceeds in the GCIM in the month the gas supplies were diverted, it would reduce ProLiance's share to 50 **percent**. However, Mr. Mierzwa reiterated his belief that **off-system sales** through gas exchanges are beyond the scope of the GCIM agreement.

Mr. Mierzwa explained that if, assuming the exchange transactions were prudent, the Commission determined that Citizens and ProLiance should be able to retain a portion of the exchange transaction proceeds, there were a number of factors which the Commission should consider. Those factors are: (1) the level of effort required to arrange a transaction; (2) the extent to which actions by ProLiance or Citizens can lead to situations where profits can be made from exchange transactions; and (3) who pays for the assets utilized to support exchange transactions.

Mr. Mierzwa noted that in the many other jurisdictions with which he was famili-

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ar, it is not uncommon for utilities to be entitled to retain approximately 25 **percent** of the proceeds from **off-system sales**. These **off-system sales** frequently generate net proceeds of a few cents per transaction and, thus, a significant level of effort is required by the utilities to generate significant off-system margins. In the case of Citizens' Gas Exchange Transactions, the proceeds were nearly \$4.00 per Dth. This would indicate that a revenue sharing percentage smaller than 25 percent for ProLiance/Citizens would be appropriate. In addition, Mr. Mierzwa testified that Citizens' ratepayers, not ProLiance, pay for the assets utilized to effectuate the exchange transactions. This includes Citizens' UGS and LNG facilities, as well as the interstate pipeline capacity utilized to divert gas supplies. Mr. Mierzwa concluded, therefore, it is appropriate for ratepayers to receive a significant share of the benefit.

With respect to a specific recommendation on sharing, Mr. Mierzwa noted that in other jurisdictions, the sharing procedures adopted for off-system sales are often consistent with those adopted for capacity release revenues. This is because **off-system sales** and **capacity release** are competing uses for pipeline capacity. ProLiance is currently entitled to retain 15 **percent** of **capacity release** revenue. For the reasons identified above, Mr. Mierzwa recommended that ProLiance/Citizens should be entitled to retain no more than 15 percent of the proceeds from exchange transactions.

Mr. Mierzwa also recommended a change to the calculation of exchange transaction proceeds from the calculation reflected in the Gas Exchange Agreement. The gross value of the transactions is currently determined based on upstream published index prices at locations near gas production fields, while it would be expected that the third-party purchasing the diverted gas would be located at a downstream market location. Thus, the gross value of the transaction would likely be understated. To reflect a more accurate determination of gross value, Mr. Mierzwa recommended that the actual sales price be utilized to determine gross value.

***14** In summary, Mr. Mierzwa asserted that Citizens' exchange transactions had an adverse impact on its sales customers. Unless Citizens can justify these transactions, he recommended an adjustment of \$960,995 in gas costs for March 2003. According to Mr. Mierzwa, if Citizens is able to demonstrate that the 2003 exchange transactions did not have an adverse impact on ratepayers, then: (1) ProLiance/Citizens should be entitled to retain no more than 15 percent of the proceeds from these exchange transactions. (2) The proceeds from the 2003 exchange transactions should be based on the actual price ProLiance was able to obtain for the diverted gas. (3) Should exchange transaction opportunities arise in the future, Citizens should seek competitive bids for the sale of these gas supplies.

6. Industrial Group's Case-in-Chief. The Industrial Group presented the testimony of Nicholas Phillips, Jr., a principal with the consulting firm of Brubaker & Associates, Inc., who recommended that the Commission reject the Gas Exchange Agreement and that all margins earned from the previous transactions be refunded to

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ratepayers.

Mr. Phillips testified that the Gas Exchange Agreement was in direct conflict with the Affiliate Guidelines adopted in GCA50. He testified that Citizens is not to subsidize its affiliate under General Guideline A or prefer its affiliate under General Guideline C. Citizens is supposed to provide comparable service to all similarly-situated marketers under General Guideline D. Mr. Phillips testified that ProLiance is retaining the profit from Gas Exchange Transactions which suggests Citizens is subsidizing its affiliate. Furthermore, he testified that Citizens' affiliate, ProLiance, is the only marketer to which Citizens has given gas exchange opportunities.

Mr. Phillips described the Gas Exchange Agreement as a formalistic method for calculating the theoretical value of the transaction. He testified that Citizens had not supplied the actual profit margin obtained by ProLiance and that the theoretical value may or may not reflect the actual profit earned by ProLiance.

Mr. Phillips testified that the GCIM was an inappropriate mechanism to split profits from gas exchange transactions with customers. He stated that the GCIM is an incentive mechanism designed to provide improvements and efficiencies associated with gas supply. According to Mr. Phillips, the Gas Exchange Agreement is not an improvement in gas supply, but an acknowledgement that excess supply may exist on winter peak days and that excess supply can be brokered by ProLiance to obtain profits. He further testified that the Gas Exchange Agreement provides a mechanism for ProLiance to profit from excess supply on Citizens' system. Therefore, he was concerned that the Gas Exchange Agreement reduces Citizens' and ProLiance's incentives with respect to controlling supply and releasing capacity.

He observed that Citizens' UGS and LNG facilities are included in rates paid by all customers. He recommended that all earnings generated from off-system sales with facilities and costs contained in customers' rates should be returned to customers in proportion to the allocation of the costs associated with the facilities contained in rates.

***15** Mr. Phillips also testified that Citizens should have filed the Gas Exchange Agreement with the Commission before the transactions took place. The transactions provided Citizens' affiliate with the exclusive opportunity to earn a profit from the sale of borrowed gas during a high price gas period. Mr. Phillips also observed that Citizens and ProLiance engaged in the Gas Exchange Transactions more than a year before requesting approval from the Commission. He testified that he was not aware of any other jurisdiction which had allowed a utility to lend gas to an affiliate without first having an agreement approved by the regulatory commission.

Mr. Phillips testified that Citizens did not require ProLiance to divert gas in equal volumes from each of the pipelines serving its distribution system. He test-

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ified this practice is contrary to the 50/50 rule Citizens imposes on its transportation customers.

Mr. Phillips responded to Citizens' testimony regarding the backstop UGS provisions. He testified that the pertinent language in the Gas Exchange Agreement does not indicate that the gas will be returned immediately, only that it will be provided prior to the June/July/August period. He further testified that ProLiance's obligation is triggered only after Citizens uses all other gas supply sources. According to Mr. Phillips, all other sources may be expensive and not in the best interest of customers. He stated that the Gas Exchange Agreement should not allow Citizens to interrupt or curtail customers to accommodate ProLiance.

7. Citizens' Rebuttal Testimony.

A. The Terms of the Gas Exchange Agreement. In its prefiled rebuttal testimony, Citizens responded to the OUCC and the Industrial Group's criticisms regarding the manner in which the 'net value' of the exchange transactions is determined. Citizens' witness Lindgren disagreed that the value of the exchange transactions to be shared with customers should be based on ProLiance's actual profit from the sale of the diverted gas. Mr. Lindgren explained that ProLiance does not necessarily sell the diverted gas. Moreover, the 'net value' calculation as set forth in the Gas Exchange Agreement guarantees that the Utility's customers will benefit from any exchange transaction, even if ProLiance's margin decreases due to unexpected decreases in commodity prices.

Citizens' witness Prentice provided additional support for the proposition that the 'net value' of the exchange transactions should be shared with customers under the GCIM. Ms. Prentice stated that she, like Mr. Bolinger, was present and participated in the GCA50 settlement negotiations. Ms. Prentice further testified that she believed the GCIM was intended to encourage and provide an incentive for ProLiance to explore and develop new methods to reduce gas costs for the Utility.

With respect to Mr. Bolinger's reliance on the fact that the term 'gas exchange' is not included in the GCIM, Ms. Prentice responded: 'During the GCIM negotiations, the utility representatives certainly did not believe we were responsible for identifying and specifically including every conceivable means by which ProLiance could create value for customers.' (Petitioner's Exhibit LSP-R, pp. 14-15.) She also stated: 'It would have been impossible for the parties to the GCA50 Settlement Agreement to include in the GCIM terms describing all the possible ways ProLiance could produce a savings for the Utility's customers at a future point in time.' (Id. at 16-17.)

***16** Ms. Prentice testified that the language of the GCIM supports Citizens' position that the exchange transactions are within the scope the GCIM. As an example, Ms. Prentice cited Section I.B., which provides: 'If the Utility's actual natural gas commodity purchase dollars are less than the sum of the Benchmark dollars, a

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positive differential exists.' According to Ms. Prentice, Section I.B., like the remainder of the GCIM refers to reductions to the Utility's actual natural gas commodity purchase dollars, not ProLiance's commodity purchase costs. Citizens' actual natural gas commodity purchase dollars were reduced to reflect the value of the exchange transactions. As such, Ms. Prentice concludes that the exchange transactions involve the Utility actually purchasing commodity at a favorable price.

Ms. Prentice also responded to Mr. Bolinger's claim that the fact that the GCA50 Settlement Agreement includes a specific incentive mechanism for unused pipeline capacity, supports the OUCC's position that off-system sales of commodity were not intended to be encompassed under the GCIM. Ms. Prentice stated:

I believe the opposite is true. The parties expressly agreed in the GCA50 Settlement Agreement to an incentive mechanism for released capacity. No such provision was made for similar transactions involving commodity. In my opinion, this is evidence of the parties' intent that the GCIM would be the sole mechanism for rewarding performance with respect to the acquisition and delivery of gas commodity. (Id. at 17, emphasis in text.)

B. The Affiliate Guidelines. Citizens also responded to the OUCC's and the Industrial Group's claims that the Gas Exchange Transactions and Gas Exchange Agreement are inconsistent with the Utility's Affiliate Guidelines. Ms. Prentice noted that the Affiliate Guidelines do not apply to transactions completed under the GCIM. The GCA50 Settlement Agreement states that the provision of services by ProLiance pursuant to the Gas Sales and Portfolio Administration Agreement ('Gas Sales Agreement') 'will not be considered a violation of the affiliate guidelines.' The Gas Sales Agreement establishes ProLiance as Citizens' gas supplier, and the GCIM is a part of the Gas Sales Agreement.

Ms. Prentice further testified that neither the Gas Exchange Transactions, nor any provision in the Gas Exchange Agreement, violates the Utility's Affiliate Guidelines. Ms. Prentice stated that the terms of the Gas Exchange Agreement are 'competitive terms,' as defined in the Affiliate Guidelines. By entering into the Gas Exchange Agreement, Ms. Prentice asserted that Citizens negotiated a reduction to what otherwise would have been a competitive cost of gas for the month of August.

Ms. Prentice and Mr. Lindgren testified that without compensation, ProLiance would have had no incentive to arrange the gas exchange transactions and thereby reduce the gas cost of Citizens' system supply customers. In addition to providing the expertise, resources and pipeline capacity necessary to complete the transactions, ProLiance assumed all associated risks. Mr. Lindgren testified that these risks included: delivery risks (i.e., ProLiance could be called upon to replace the gas at any time), credit risks and price-related risks.

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*17 Mr. Lindgren testified that the backstop provision represents a significant benefit to Citizens' customers. Mr. Lindgren described a situation that occurred in April of 1996 in which low storage volumes caused the Utility to institute a 'buy through option,' under which interruptible customers could choose to allow Citizens to purchase additional gas via the capacity release market and charge the interruptible customer directly. Mr. Lindgren stated that, had circumstances similar to those that occurred during April of 1996 arisen in 2003, the backstop provision would have been of significant benefit to Citizens. Mr. Lindgren also testified that the backstop provision in no way requires Citizens to interrupt or curtail supply to customers before requiring ProLiance to return the exchanged gas to the city gate and that Citizens would not do so.

Ms. Prentice stated that Citizens could not have sought and obtained bids from other gas marketers without breaching the Gas Sales Agreement, under which ProLiance is the exclusive provider of supply services to Citizens. Even if soliciting bids were not a breach of the Gas Sales Agreement, Mr. Lindgren testified that doing so would not have been feasible. Mr. Lindgren stated that he believes it would have taken longer than the time frame Citizens and ProLiance estimated they had to complete the 2003 exchange transactions just to solicit and obtain bids, including the performance of some form of due diligence (E.g. credit checks) on potential bidders.

Ms. Prentice responded to the OUCC's assertion that the Gas Exchange Agreement gives ProLiance preferential access to Citizens' storage. Ms. Prentice stated that ProLiance is in no way given access to the Utility's storage capacity under the terms of the Gas Exchange Agreement. She stated: 'Citizens Gas uses its storage capacity to meet the needs of its system supply customers, and in the case of the exchange transactions, it was utilized to provide a distinct benefit to those system supply customers.' (Id. at 10-11.)

Ms. Prentice also testified that the fact that Citizens does not intend to offer transportation customers the opportunity to borrow gas during the winter and return it in the summer, does not make the Gas Exchange Agreement discriminatory. Ms. Prentice stated that Citizens arranged the Gas Exchange Transactions with ProLiance to provide a benefit (i.e., reduced gas costs) to all of its system supply customers. She stated that this is very different from permitting a single transportation customer to 'borrow' gas during the winter months and return the gas during the summer months. Ms. Prentice claimed such an arrangement might benefit that single customer, assuming it could purchase the replacement gas at a lower cost, but it could place Citizens' other customers at a substantial risk.

Mr. Lindgren testified that the Utility's '50/50 Rule' did not apply to the Gas Exchange Transactions. The '50/50 Rule' did not take effect until June of 2003 and even if it had been effective in February/March 2003, it applies only to deliveries of gas by third Party Suppliers to Citizens' system.

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*18 C. The OUCC's Proposed Retroactive Disallowance of Gas Costs Approved in the GCA. Citizens also testified that it acted prudently in its purchase of gas and use of system storage in March 2003. Mr. Lindgren stated that during the winter of 2002-2003, Citizens used 2.9 BCF more system storage gas than had been planned for the period, despite the fact that system send-out was 552,531 MMBTU less than normal. Moreover, in February/March of 2003, Citizens reduced its purchases of take-or-release ('TOR') gas by 580,244 MMBTU and 173,135 MMBTU, respectively.

Mr. Lindgren stated that Citizens cannot replace all of its TOR gas with gas from storage. The Utility must consider a number of factors in determining how much gas it can withdraw from storage, including: weather patterns, storage withdrawal ratchets, as well as the cost of refilling storage. Mr. Lindgren testified that 'drawing more heavily on gas in storage than was agreed upon in the March 2003 supply plan could have resulted in Citizens Gas' inability to meet its system supply needs in April and May, 2003.' (Petitioner's Exhibit LCL-R at 8.) Mr. Lindgren cited Citizens' implementation of the 'buy through option' in April of 1996 as an example.

Mr. Lindgren also described the many efforts Citizens made during the winter of 2003 to reduce customer gas costs. Mr. Lindgren noted that the OUCC publicly lauded the Utility's efforts. In Re Northern Indiana Public Service Company, Cause No. 41338-GCA4, OUCC witness Bolinger testified regarding the price volatility mitigation efforts made by Citizens in the winter of 2003. Mr. Bolinger stated that Citizens' 'efforts paid big dividends this winter, especially in March 2003 ...Citizens deserves real credit for the improvements it has made.'

8. Commission Discussion and Findings. This subdocket proceeding concerns both a rate issue reserved in the primary docket of 37399 GCA84, as well as a question relating to the prospective application of the Gas Exchange Agreement. In Cause No. 37399 GCA84, Citizens proposed to flow to its GCA customers a credit of \$252,410, reflecting a portion of proceeds derived from certain Gas Exchange Transactions between Citizens and ProLiance. One of the questions before the Commission is whether the \$252,410 credit is appropriate, as Citizens maintains, or whether a different credit amount should be recognized.

In addition, on a prospective basis, the Gas Exchange Agreement between Citizens and ProLiance is before the Commission for review pursuant to the terms of the Affiliate Guidelines established in Consolidated Cause Nos. 37394GC50S1, 37399GC50S1 and 42233. In that consolidated proceeding, the Commission approved the GCA50 Settlement Agreement that included, among other provisions, the Affiliate Guidelines governing transactions between Citizens and its unregulated affiliates. The Affiliate Guidelines provide that all transactions between Citizens and its affiliates shall be in accordance with a written contract filed with the Commission. The Affiliate Guidelines also provide that the OUCC may challenge affiliate contracts and, upon such challenge, the OUCC has the burden of establishing that the contract or any provision thereof is not in the public interest. On motion by the In-

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dustrial Group, the Commission has taken administrative notice of the GCA50 Settlement Agreement, with Appendices E and G, as well as the July 24, 2002 Commission Order approving it. The Affiliate Guidelines are set forth in Appendix G to the GCA50 Settlement Agreement, and Appendix E contains the GCIM pursuant to which Citizens proposes to share the proceeds in dispute.

***19 A. Affiliated Interests.** It has been established in this proceeding that ProLiance is an affiliate of Citizens. The Commission realizes that negotiations between affiliates may sometimes appear to be less than 'arm's length' and thus, agreements that result from these negotiations must be carefully scrutinized.

Mr. Lindgren is Vice President of Gas Operations for Citizens. He also has been a member of the Board of Directors of ProLiance for approximately five years. His responsibilities as a Director of ProLiance include general management and oversight duties. When asked during the hearing to elaborate on his Director's duties at ProLiance, Mr. Lindgren responded that he basically functions in a strategic capacity, and provides long-term decision support. Mr. Lindgren also is an officer of Citizens By-Products Coal Company, which has an ownership interest in ProLiance.

Mr. Lindgren testified that he negotiated the terms of the Gas Exchange Agreement between Citizens and ProLiance, and represented the interests of Citizens and Citizens' customers, while at the same time he was fulfilling his duties as a Director of ProLiance. He stated that he believes Citizens' interests to be the same as Citizens customers' interests. Mr. Lindgren admitted that he had a duty as a ProLiance Director at the same time he negotiated the Gas Exchange Agreement on behalf of Citizens.

Mr. Lindgren may believe that he can represent the best interests of Citizens, Citizens' ratepayers and ProLiance at the same time without compromising any party's interest. However, the best interests of ProLiance, as a gas marketer; of Citizens, as a public charitable trust and municipal utility; and ultimately of Citizens' ratepayers, are not identical. Mr. Lindgren cannot reasonably be expected to anticipate and resolve the instances in which the interests of ProLiance, Citizens and the ratepayers may diverge. Mr. Lindgren's fulfillment of multiple roles during the negotiation of the Gas Exchange Agreement may not have served the best interests of Citizens' ratepayers.

B. Applicability of the Affiliate Guidelines to the Gas Exchange Agreement. The GCA50 Settlement Agreement resolved six years of litigation concerning issues under the Commission's regulatory jurisdiction. The GCA50 Settlement Agreement contains regulatory provisions to promote a more competitive gas market. Article IV of the Settlement Agreement provides that the utilities will reaffirm their commitment to a 'healthy competitive market' and host seminars and workshops for competitors and transport-eligible customers to explain the settlement provisions designed to promote a competitive market. Chief among those provisions are the Af-

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affiliate Guidelines. ProLiance is a signatory to the GCA50 Settlement Agreement, and the Commission found in the GCA50 Order that the Affiliate Guidelines apply to Citizens' relationship with ProLiance. Therefore, ProLiance is an affiliate of Citizens and subject to the Affiliate Guidelines.

*20 However, Citizens has proposed in this Cause that the Affiliate Guidelines do not apply to the Gas Exchange Agreement. This proposal is based on the theory that: (1) the gas exchange transactions are part of the GCIM; (2) the GCIM is part of the Gas Sales Agreement, and (3) the provision of services by ProLiance pursuant to the terms of the Gas Sales Agreement is not considered a violation of the Affiliate Guidelines. We agree that the GCIM is part of the Gas Sales Agreement and that the GCA50 Settlement Agreement exempts ProLiance's provisioning of service under the Gas Sales Agreement from the Affiliate Guidelines.

Citizens also argued that even if the gas exchange transactions are not encompassed by the GCIM, they do not violate the Affiliate Guidelines. The theory of this proposal is that the terms of the Gas Exchange Agreement are 'competitive terms' as defined in the Affiliate Guidelines.

In order for the Commission to accept Citizens' proposal that the Affiliate Guidelines do not apply to the Gas Exchange Agreement, the Commission must determine whether the Gas Exchange Transactions are part of the GCIM. The evidence does not show that any specific language in the GCA50 Settlement Agreement, the GCIM Agreement or the Affiliate Guidelines references gas exchanges, gas loans, or off-system commodity sales.

Appendix E of the GCA50 Settlement Agreement is the GCIM Agreement. Section I of this Agreement applies to commodity purchases, and provides the sharing ranges that Citizens proposes to use to share the calculated 'net value' of gas exchanges. The first sentence of Section I states: 'This section applies to and is intended to accommodate the types of monthly and daily commodity purchases frequently made by the Utility.' The record in this Cause does not support the contention that the Gas Exchange Transactions are the type of 'monthly or daily commodity purchases frequently made' by Citizens. In fact, the record indicates that Citizens made one Gas Exchange Transaction in February 2003 and four Gas Exchange Transactions in early March 2003. No such transactions were made before that time, and none have been made since.

Even a liberal interpretation of the word 'frequently' does not permit the Commission to find that the Gas Exchange Transactions in this Cause are the type of commodity purchases that are made often by Citizens. Furthermore, the use of the words 'monthly' and 'daily' in the introductory sentence of Section I provides additional support that the type of commodity purchases subject to the GCIM are those that occur on a regular or 'frequent' basis. A clear reading of the GCIM reveals no language that suggests gas exchanges, gas loans or off-system sales transactions are within the GCIM's scope. The Commission is persuaded by the

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testimony of the consumer party witnesses, who explained that the GCIM provides rewards when ProLiance acquires gas supplies for Citizens below benchmark prices, and that the GCIM contemplates a fundamentally different type of transaction from Citizens making gas supplies available to ProLiance to support unregulated marketing activities.

***21** Section I of the GCIM applies to non-hedged, monthly and daily commodity purchases. Section I specifies a process for comparing the 'actual natural gas commodity purchase dollars' to the 'Benchmark dollars' every month. The 'Benchmark dollars' provide a performance benchmark, based on published price indices. If the 'actual natural gas commodity purchase dollars' are less than the 'Benchmark dollars,' then Citizens and its GCA customers share the savings according to the sharing ranges in Section I. Section I rewards (or penalizes) superior (or inferior) performance at purchasing monthly and daily commodity supplies for GCA customers. Section I provides rewards only when commodity is acquired at a cost below published benchmarks.

A key to Section I of the GCIM is the ability to make a reasonable comparison between Citizens' (frequently made) monthly and daily commodity purchases and the published benchmark prices. Mr. Bolinger referred to this as the 'apples to apples' comparison. This requires that actual commodity purchases be compared to the corresponding benchmark prices for the same time period.

However, the Gas Exchange Agreement treats net gas exchange proceeds from February and March, 2003 as if they were reductions to the August 2003 actual commodity purchase dollars for GCIM purposes. The nexus between February/March purchases and August benchmarks does not exist, at least for GCIM purposes. Therefore, the Commission finds that a comparison of (infrequently made) February and March Gas Exchange Transaction proceeds to actual August 2003 commodity costs is not a reasonable comparison to published benchmarks prices pursuant to Section I of the GCIM.

As to Citizens' argument that it relied on representations made by the OUCC at a February 26, 2003 meeting as justification for going forward with the Gas Exchange Transactions, we find there is not sufficient evidence for Citizens to have concluded that the OUCC approved of the transactions. While the OUCC did not explicitly dismiss Citizens proposal, and it seems even recognized the element of public benefit, the evidence supports a conclusion that at the least, the OUCC expressed a desire to conduct further review of the proposal. Moreover, we are troubled by the fact that neither Citizens nor the OUCC memorialized its impressions of the other's views as taken from the discussion of February 26, 2003, since the differences cited in the testimony of the parties are at the heart of this case.

The Commission finds that the GCIM does not apply to the February and March 2003 Gas Exchange Transactions. Such transactions are beyond the scope of the GCIM. The

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Gas Exchange Transactions are not part of the services provided by ProLiance pursuant to the Gas Sales Agreement. The Commission finds that Affiliate Guidelines are applicable to the Gas Exchange Agreement.

C. Application of the Affiliate Guidelines to the Gas Exchange Agreement. We will now examine the particular Affiliate Guidelines that are most relevant to the Gas Exchange Agreement.

*22 i. General Affiliate Guideline B: Separation of Regulated and Non-Regulated Operations. The separation of the Utility's regulated operations from its own and its Affiliates['] non-regulated operations is necessary to prevent potential cross-subsidies. To the maximum extent practicable, the Utility shall separate its regulated operations from its own, and its Affiliates non-regulated operations. Instances where such separation does not exist must otherwise be in compliance with these Affiliate guidelines and the Cost Allocation Guidelines.

As previously indicated, Mr. Lindgren is Vice President of Gas Operations for Citizens. He is responsible for gas operations, including gas supply for the regulated utility. Mr. Lindgren is also a board member of ProLiance. Mr. Lindgren testified that he represented Citizens and its ratepayers during the negotiations that led to the Gas Exchange Agreement, while at the same time fulfilling his duties as a Director of ProLiance.

Both the OUCC and the Industrial Group expressed concern about the lack of separation between Citizens' regulated utility operation and its non-regulated affiliate operations under the subsidiary, Citizens By-Products. Citizens By-Products owns Citizens' equity interest in ProLiance. The lack of separation between regulated utility operations and non-regulated affiliate operations is illustrated by the positions that Mr. Lindgren simultaneously occupies for the Utility, Citizens By-Products and ProLiance. The evidence demonstrates that Citizens is not, 'to the maximum extent practicable,' separating its regulated activities from its affiliated non-regulated activities.

ii. General Affiliate Guideline C: No Discrimination. The Utility shall not discriminate in favor of or otherwise give preferential treatment to its Affiliates, its Affiliates' customers or the Utility's own non-regulated activities.

The Gas Exchange Agreement enables ProLiance, with Citizens' consent, to divert Citizens' flowing gas supply volumes at times of peak prices and then return the volumes 'in kind' during the spring or summer, typically characterized by more moderate and stable gas prices. ProLiance is an affiliate that functions in the competitive marketplace. The Gas Exchange Agreement provides significant profit opportunities for ProLiance, to the exclusion of all other gas marketers and parties who may also be interested in borrowing gas at peak prices and returning it under a firm 'hold harmless' clause, given that the replacement gas would typically be procured at lower prices.

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There was a great deal of debate about Citizens' ability to open 'gas exchange' or 'gas lending' opportunities to non-affiliated market participants. Citizens asserted that ProLiance is the only supplier with whom Citizens could have arranged the Gas Exchange Transactions because ProLiance is Citizens' exclusive provider of supply services. ProLiance sells gas supplies to Citizens pursuant to a separate supply contract that was approved as part of the GCA50 Settlement Agreement. That supply contract, the Gas Sales Agreement, provides that ProLiance will be the exclusive seller of system supplies to the Utility.

***23** The Gas Exchange Agreement, on the other hand, allows ProLiance to divert flowing system supplies in order to make 'off-system' sales, while compensating Citizens and promising to return the diverted supplies under stated terms and conditions. ProLiance used the diverted gas in its capacity as an unregulated marketer, not in its role as system supplier to Citizens. While Citizens questioned whether the term 'loan' was appropriate, the transactions involved Citizens making gas available to ProLiance for a specified time period in order to support ProLiance's activity in the unregulated market, with ProLiance providing compensation to Citizens for the use of that gas. The Gas Exchange Transactions, accordingly, do not involve ProLiance selling gas supplies to Citizens, but involve Citizens providing a form of service to ProLiance. There is no provision in the supply contract, for example, designating ProLiance as the exclusive borrower of gas from Citizens. Such activity, therefore, is not encompassed by ProLiance's supply contract with Citizens.

Our approval of the supply contract in the GCA50 Settlement Agreement, and our approval of the exemption of the supply contract from the Affiliate Guidelines, was in the context of those 'monthly and daily commodity purchases frequently made by the Utility,' the purchase price of which can be evaluated in light of a known 'benchmark price.' We have already discussed how a comparison of a benchmark price for the month of August with the cost of gas in February/March is inconsistent with the GCIM's intent to compare a purchase price with a benchmark price for the same time period. While Citizens relies on the ultimate reduction in gas costs to its customers as fitting both the intent and language of GCIM process, we find it more reasonable to conclude that the GCIM process does not extend to gas exchange transactions.

Citizens also argues it would have been impossible to solicit bids in the short time frame that existed in February/March 2003. The OUCC and the Industrial Group counter that there are numerous large and sophisticated players in the market that could have very quickly made proposals to Citizens to exchange volumes and return them later. The debate about what Citizens could have done in the short February/March 2003 time frame is largely academic, since Citizens completed those transactions about eighteen (18) months prior to filing the Gas Exchange Agreement with the Commission.

Going forward, the Gas Exchange Agreement provides a long-term, exclusive gas

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lending arrangement between Citizens and ProLiance. There is no persuasive evidence that an on-going gas exchange/gas lending program could not be opened up to competitive and non-discriminatory participation. There are other large players in the gas market capable of diverting/borrowing volumes from Citizens and then returning them 'in kind' for a competitively determined price. There is no reasonable justification for an exclusive and preferential gas lending program available only to ProLiance. The Commission finds that the Gas Exchange Agreement is preferential to Citizens' affiliate, ProLiance. No other gas marketers or large volume customers were permitted to make proposals or bid for the right to participate in gas exchanges. The Commission finds that the Gas Exchange Agreement violates the prohibition against discrimination and preferential treatment of utility affiliates.

***24** Fundamentally, a desire to act quickly does not suspend the operation of the Affiliate Guidelines. The Guidelines do not contain any provision indicating that the agreed standards and requirements only apply conditionally, or suggesting in any way that discriminatory preferences in favor of affiliates are permissible if and when time is short. By the reasoning suggested by Citizens, the Affiliate Guidelines would not be applicable whenever an opportunity of short duration arises in a fast-moving, volatile market. The clear prohibitions against discriminating or granting preferences in favor of ProLiance and requiring comparability of service are inconsistent with a scheme in which ProLiance becomes the exclusive beneficiary of such market opportunities.

iii. Specific Affiliate Guideline 3: The Utility shall not give preference to or discriminate in favor of its Affiliates, its Affiliates' customers or its own non-regulated operations in matters including, but not limited to, the allocation, assignment, release, or transfer of rights to intrastate or interstate capacity, use of Utility distribution facilities, storage on system, rights to storage off system, or in the sale of gas.

Costs associated with Citizens' on-system storage are embedded in its base rates and are recovered from both sales and transportation customers. Specific Affiliate Guideline 3 prohibits Citizens from providing ProLiance or other affiliates with preferential access to these system resources paid for by ratepayers.

In the Gas Exchange Transactions, flowing pipeline supplies intended for Citizens' system needs were diverted to ProLiance's use in the unregulated market, and the diverted supplies were replaced with gas from Citizens' on-system storage facilities intended to serve ratepayers. When ProLiance later returned the gas volumes, the deliveries were injected into storage to replace the gas previously withdrawn from storage. As part of the compensation terms, ProLiance paid the incremental costs associated with utilization of the storage facilities. ProLiance's redelivery obligation is subject to acceleration in specified circumstances tied to the operational status of Citizens' storage facilities.

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While the transactions were structured so that ProLiance did not receive gas directly withdrawn from on-system storage, on-system storage was being utilized to support ProLiance's unregulated marketing activities. Specific Affiliate Guideline 3 is not narrowly phrased to prohibit only a direct sale of gas from storage to an affiliate, but rather prohibits preference or discrimination in 'matters including, but not limited to' any 'transfer of rights' to on-system storage. The use of on-system storage for the benefit of ProLiance in a non-competitively bid context, therefore, constitutes a discriminatory preference for the affiliated marketer.

The OUCC challenged Citizens' decision to utilize its economical storage reserves to support ProLiance's unregulated marketing activities, instead of using those resources to provide more economical service to ratepayers. Citizens responded by arguing it would have been imprudent to withdraw the storage volumes in question for use in serving its sales customers. Citizens reduced its physical gas assets so that ProLiance would have additional gas supplies to sell into a lucrative market, at a time when Citizens felt it would be imprudent to withdraw more gas from storage for ratepayer use. The exchange transactions, conducted exclusively with ProLiance, physically altered the status of Citizens' on-system storage capabilities, and thus fall within the scope of Specific Affiliate Guideline 3.

iv. Conclusion Regarding Affiliate Guidelines. We have reviewed the Gas Exchange Agreement for consistency with the Affiliate Guidelines agreed to in the GCA50 Settlement Agreement. We have found several conflicts between the terms of the Gas Exchange Agreement and the Affiliate Guidelines. In general, the Gas Exchange Agreement is discriminatory and preferential to ProLiance. The Gas Exchange Agreement provides that municipal utility storage facilities will be dispatched to create gas lending and off-system sales opportunities for ProLiance. Potential competitors to ProLiance were not offered the opportunity to bid for such treatment. Such preferential treatment of ProLiance is inconsistent with the Affiliate Guidelines and the development of the more healthy competitive market envisioned by the GCA50 Settlement Agreement.

*25 Citizens also contends that even if the Gas Exchange Transactions were not encompassed under the GCIM, the terms of the Gas Exchange Agreement are 'competitive' terms. This argument is based on the notion that the Gas Exchange Transactions, accomplished through the Gas Exchange Agreement, resulted in what otherwise would have been a competitive cost of gas in August. According to Citizens, if the cost of gas that it otherwise would have purchased in August was considered competitive, then a reduction to that cost can only make it more competitive. This is an interesting, albeit weak, argument. Clearly, the furtherance of competition as promoted and extensively discussed in the GCA50 Settlement Agreement contemplates something more than a unilateral determination by the Utility that the competition requirements of the Settlement Agreement can be satisfied simply by examining the nature of the transaction and without regard to transacting with non-affiliates.

D. Conclusion Regarding the Gas Exchange Agreement. The GCA50 Settlement Agree-

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ment devoted significant attention to discussing and prohibiting certain activities in regard to affiliate relationships. A gas exchange agreement may be an appropriate tool for Citizens to use in furtherance of its obligation to provide gas to its customers at the lowest reasonable cost, but not at the expense of violating its governing Affiliate Guidelines. For all the reasons discussed above, we find that the Gas Exchange Agreement as proposed by Citizens violates the Affiliate Guidelines and is not in the public interest. The Gas Exchange Agreement, therefore, is disapproved.

E. Conclusion Regarding the Gas Exchange Transactions. While we cannot approve a gas exchange agreement that violates applicable standards governing affiliate relationships, we also cannot overlook the fact that these particular Gas Exchange Transactions resulted in a financial benefit to ratepayers. Also, we agree with Citizens that these particular transactions involved an element of risk and it is reasonable that there be some incentive for taking that risk. Since the transactions have already occurred, we do not find it appropriate to take action now that would cause customers to lose any of that benefit. The question we now face is what the appropriate amount of customer benefit should be with respect to these specific, historical transactions.

Since we have determined that the Gas Exchange Transactions are not encompassed in the GCIM as a commodity purchase, the GCIM sharing mechanism utilized by Citizens and ProLiance has no presumptive applicability. We have testimony from the OUCC that other jurisdictions have adopted sharing procedures for gas exchange transactions that are consistent with capacity release activities. Pursuant to the GCA50 Settlement Agreement, and in the absence of an operative alternative agreement, there is a customer/utility sharing mechanism of 85/15 **percent** attached to the net proceeds derived from capacity auctions. The OUCC testified that **off-system sales** (gas exchange transactions) and capacity release are competing uses for dealing with pipeline capacity. Based on the evidence presented in this proceeding, we find the capacity auction sharing provision applicable to Citizens is the most reasonable sharing provision to be applied in this Cause to the net value of \$841,368 derived from these particular Gas Exchange Transactions. Accordingly, a total credit adjustment to customers, derived from the Gas Exchange Transactions, should be \$715,162.80.

***26** Notwithstanding the fact that we have found the sharing mechanism designed for capacity auctions to be the best available mechanism for sharing the net proceeds of these historical transactions, the Commission has before it no sharing mechanism specifically designed for possible, future gas exchange transactions occurring in a competitive context. The Commission remains open to a proposed mechanism for allocating the net proceeds realized from the transactions that, within the framework of the Affiliate Guidelines, is directly tied to the nature of the transactions

IT IS THEREFORE ORDERED BY THE INDIANA UTILITY REGULATORY COMMISSION THAT:

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1. The Gas Exchange Agreement between ProLiance Energy, LLC and Citizens Gas & Coke Utility is not in the public interest and is not approved.
2. Citizens shall make a total credit adjustment to customers, derived from the Gas Exchange Transactions, of \$715,162.80 in gas costs for March 2003.
3. In accordance with I.C. 8-1-2-70, Citizens shall pay the following itemized charges within twenty days from the date of the Order to the Secretary of this Commission, as well as any additional costs which were or may be incurred in connection with this Cause.

Commission Charges	\$200.00
Reporting Charges	245.33
Legal Advertising Charges	49.13
OUCC Charges	320.00

Total	<u>\$814.46</u>

4. This Order shall be effective on and after the date of its approval. APPROVED:
SEP 22 2005

END OF DOCUMENT

Westlaw.

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Re Delmarva Power & Light Company
 PSC Docket No. 06-285F
 Order No. 7219

Delaware Public Service Commission
 July 3, 2007

BY THE COMMISSION:

*1 AND NOW, this 3rd day of July, 2007;

WHEREAS, the Commission having received and considered the Findings and Recommendations of the Hearing Examiner ('Report') issued in the above-captioned docket, which was submitted after a duly noticed public evidentiary hearing;

AND WHEREAS, the Commission finds that the proposed rates and tariff changes are just and reasonable and that adoption of the Hearing Examiner's Report is in the public interest; now, therefore,

IT IS ORDERED:

1. That, by and in accordance with the affirmative vote of a majority of the Commissioners, the Commission hereby adopts the June 13, 2007 Findings and Recommendations of the Hearing Examiner, appended to the original hereof as Attachment 'A.'

2. That the Commission approves Delmarva Power & Light Company's proposed rates and tariff changes (made effective on a temporary basis on March 20, 2007) with meter readings on and after April 1, 2007 until October 31, 2007, as shown below and in the Proposed Settlement Agreement which is appended to the original hereof as Attachment 'B:'

	GCR	GCR
	Demand	Commodity
Rate Schedules	Charge	Charge
RG, GG and GL	N/A	102.357[/ccf
Non-electing	\$9.98/Mcf of	\$8.8683/Mcf
MVG	Billing MDQ	
Electing MVG &	\$9.98/Mcf of	Varies
LVG	Billing MDQ	
Standby Service	\$9.98/Mcf of	N/A
	Standby MDQ	

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3. That the Commission approve as just, reasonable and in the public interest the Company's proposals to: a) reconcile and true-up actual versus estimated Weighted Average Commodity Cost of Gas ('WACCOG') assignments for sales under the Flexibly Priced Sales service to restate fuel revenue and shared margin revenue credits; and, b) to reconcile and true-up actual versus estimated WACCOG assignments for sales under the Large Volume Gas service and for so-called 'electing' customers taking service under the Medium Volume Gas service.

4. That Delmarva Power & Light Company shall file with the Commission, within thirty days of the date of this Order, a revised tariff reflecting the revised rates and tariff changes as contained herein.

5. That the Commission reserves the jurisdiction and authority to enter such further Orders in this matter as may be deemed necessary or proper.

ATTACHMENT 'A'

FINDINGS AND RECOMMENDATIONS OF THE HEARING EXAMINER

Ruth Ann Price, duly appointed Hearing Examiner in this docket pursuant to 26 Del. C. § 502 and 29 Del. ch. 101, by Commission Order No. 7039, dated October 3, 2006, and Order No. 7141, dated March 20, 2007, hereby reports to the Commission as follows:

I. APPEARANCES

On behalf of the Applicant, Delmarva Power & Light Company ('Delmarva' or 'the Company'): TODD GOODMAN, ESQUIRE

On behalf of the Public Service Commission Staff ('Staff'): Ashby & Geddes

BY: JAMES McC. GEDDES, ESQUIRE

On behalf of the Division of the Public Advocate ('DPA'):

G. ARTHUR PADMORE, PUBLIC ADVOCATE BO SHEN, PH.D, PUBLIC UTILITIES ANALYST

II. BACKGROUND

A. THE APPLICATION

1. On August 31, 2006, Delmarva filed its annual application ('the application ') with the Delaware Public Service Commission (the 'Commission') to adjust its Gas Cost Rate ('GCR') factors, effective on and after November 1, 2006, with proration, and with such revised factors to continue in effect until October 31, 2007. The proposed rates, as compared to the current, approved rates are as follows:

proceeding. No other party petitioned for intervention.

7. On November 7, 2006, the Company announced, through publication in The News Journal newspapers, that a public comment hearing would be held on November 29, 2006 at the Carvel State Office Building in Wilmington. Further, the notice stated that a formal evidentiary hearing would be held on May 11, 2007 for the Company and all intervenors.

B. PUBLIC COMMENT SESSION

8. A duly noticed public comment hearing was conducted on the evening of November 29, 2006 from approximately 7:00 p.m. to 7:16 p.m. at the Carvel State Office Building in Wilmington, Delaware. [FN1] In addition to publication of the notice in The News Journal newspaper, the Company directly notified the organizations that participate in its 'Project Concern' as well as the Association of Community Organizations for Reform Now ('ACORN').

9. Representatives from the Commission Staff, the DPA, and the Company appeared at the hearing. The hearing initially began at 7:00 p.m. I adjourned the hearing for approximately ten (10) minutes to allow members of the public to arrive. At 7:11 p.m., I again called to session to order and, finding that no members of the public had arrived, I adjourned the meeting at approximately 7:16 p.m.

C. THE SUPPLEMENTAL APPLICATION

10. On February 23, 2007, Delmarva filed a supplement to adjust its annual Gas Cost Rate ('GCR') factors, effective on and after April 1, 2007, with proration, and with such revised factors to continue in effect until October 31, 2007. The proposed rates, as compared to the current, approved rates are as follows:

	Initial Application filed on 8/31/2006	Supplemental Application filed on 2/23/2007		
	GCR Demand Charge	GCR Commodity Charge	GCR Demand Charge	GCR Commodity Charge
Rate Schedules RG, GG and GL	N/A	106.972[/ccf	N/A	102.357[- /ccf
Non-electing	\$9.98/Mcf of	\$9.3298/Mcf	\$9.98/Mcf of	\$8.8683/- Mcf
MVG	Billing MDQ		Billing MDQ	
Electing MVG & LVG	\$9.98/Mcf of Billing MDQ	Varies	\$9.98/Mcf of Billing MDQ	Varies
Standby Service	\$9.98/Mcf of	N/A	\$9.98/Mcf of	N/A

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Standby MDQ

Standby MDQ

11. In its supplemental filing, the Company explained that its submission was to inform the Commission of a projected over-recovery, in excess of the deadband provided in the Gas Service Tariff, and to propose a GCR that more closely aligned collections with expenses. Ex. 10. The Company noted that the average firm purchased gas cost for the 2006-2007 GCR period was expected to be \$9.65/Mcf versus the \$10.34Mcf provided in the original filing on August 31, 2006. The difference in the purchased gas cost factors represents a decrease of \$0.69/Mcf, which Delmarva attributed to the decrease in gas commodity prices stemming from the unusually warmer weather than normal in the mid-Atlantic region combined with increases in flowing gas supplies. Ex. 10.

12. The Company further stated that without an adjustment to the proposed GCR, Delmarva projected an over-recovery of \$6.2 million, or 4.8% of projected firm purchased gas as costs for the November 2006 through October 2007 period. Ex. 10.

13. The impact on customers would mean that those served under service classifications RG, GG and GL would experience an approximate 9.6% decrease in the level of the GCR. Residential space heating customers using 120 Ccf per month in the winter heating months would experience a decrease of \$5.54 or 3.1% per month in their total bill. Commercial and industrial customers using 'GG' and non-electing 'MVG' service classifications would experience decreases in their winter bills in the range of 2.1% to 3.5% and 3.5 to 4.3%, respectively, in monthly billings depending on applicable service classification and load/consumption characteristics.

14. Pursuant to PSC Order No. 7141, on March 20, 2007, the Commission allowed the new proposed GCR factors, reconciliation and true-ups, and non-firm surcharge to become effective on a temporary basis, subject to refund, effective with meter readings on and after April 1, 2007, with proration.

15. Notices of the supplemental application, including information on how to intervene in the proceeding, were published on March 23 and 24, 2007 in The News Journal newspaper. The notices also provided a deadline of April 18, 2007 by which the public could petition to intervene and submit comments concerning the Company's proposal. The Commission Staff did not receive any comments from the public regarding the supplemental application.

III. SUMMARY OF THE EVIDENCE

16. On May 11, 2007, a public comment session and an evidentiary hearing was held for Delmarva's supplemental application at the Carvel State Office Building in Wilmington. The record, as developed at the hearing, consists of a 62-page verbatim transcript and 12 exhibits. No members of the public attended either the public comment session or the evidentiary hearing.

A. Summary of Testimony.

17. At the evidentiary hearing, the parties presented their witnesses who summarized their testimonies and adopted their prefiled testimonies for the record.

18. Company's Direct Testimony. With its application, Delmarva submitted the pre-filed testimony of four witnesses. At the evidentiary hearing, C. Ronald McGinnis, Jr., Regulatory Team Lead, Regulatory Affairs Department for PHI Service Company and William T. Bacon, Director -- Regulatory & Natural Gas Planning for PHI Service Company and W. Thomas Bacon, Jr., Director-Gas Supply & Regulatory Planning, appeared to give live testimony. C. Ronald McGinnis, Jr., adopted as his own testimony (Ex. 3), the prefiled testimonies of Hallie M. Reese (Ex. 4) and Charles L. Driggs (Ex. 5). Mr. Bacon sponsored his own prefiled testimony (Ex.6).

19. Mr. McGinnis presented a chart, which I have duplicated below, demonstrating the impact on each rate class for the proposed GCR.

	Present GCR	Proposed GCR	
Rate Schedules	Commodity Charge	Commodity Charge	Change
RG, GG and GL	118.384[/ccf	106.972[/ccf	(1.1412) [/ccf
Non-electing	\$11.0279/Mcf	\$9.3298/Mcf	(\$1.6981)Mcf
MVG	Billing MDQ		Billing MDQ
Electing MVG & LVG	Varies	Varies	N/A
LVG and MVG	\$6.20/Mcf of MDQ	\$9.98 Mcf MDQ	\$3.78/Mcf MDQ

*2 Ex. 3 at 3. This chart shows that not only residential customers but also non-electing MVG customers will experience a significant rate decrease.

20. Mr. McGinnis provided testimony regarding development of the proposed GCR and its impact on the various customer classes, reconciliation of actual versus estimated weighted average commodity cost of gas ('WACCOG') assigned to LVG and MVG customers; reconciliation of actual versus estimated WACCOG of gas assigned to Flexibly Priced Service Customers and true up of fuel expense and margins, the audit of GCR and margin sharing for the 2005 calendar year, and prior adjustments contained in the actual data used to develop the deferred fuel balance as of July 31, 2006. Ex. 3.

21. Mr. McGinnis's prefiled testimony noted that the Company projects an under-recovery balance of \$4,298,300 based upon nine months of historical data and three months of updated estimates. Ex. 3 at 5. The amount is within the 6% deadband for a supplemental GCR filing of 6% under-recoveries.

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22. Further, Mr. McGinnis summarized the methodologies used: (a) to develop the GCR factors and the credits associated with certain shared margin revenues; (b) to perform the reconciliations and true-ups which compare and take into account for recovery in this case the differences between costs and revenues estimated in the prior years' GCR proceedings with actual costs and revenues incurred; and (c) to calculate the non-firm surcharge. Mr. McGinnis also described various accounting adjustments that were made in the preparation of the filing and addressed the then applicable status of the prior GCR proceeding and other ongoing proceedings involving gas matters.

23. Mr. McGinnis concluded by observing that gas costs included in the proposed GCR represent approximately 73% of the total bill amount for residential customers. The effect of the proposed decrease to the GCR on residential space heating customers using 120 Ccf per month in the winter months would be a decrease of \$13.69, or 7.2%. Consequently, customers using 120 Ccf would experience a reduction from \$189.61 per month to \$175.92 per month. Commercial and industrial customers' bills would decrease 5.0% to 12.5% in the commodity portion of their bills. Ex.3 at 12.

24. Company witness W. Thomas Bacon, Jr., Director -- Gas Supply & Regulatory Planning for PHI Service Company, provided testimony on the following items: (a) Delmarva's actual and estimated interstate pipeline transportation and storage rates; (b) forecasted natural gas commodity prices; (c) an update of the Natural Gas Hedging program; (d) firm natural gas purchase requirements; (e) the Company's capacity release and off-system sales activity; and (f) update on planned capacity additions. (Ex. 6.)

25. Regarding the available natural gas supply, Mr. Bacon testified that the Company has 169,230 Mcf of peak or design day supply to meet firm sales customer needs, but based upon projected requirements there will be a shortfall of 4,117 Mcf. Mr. Bacon noted that this compares to an estimated design day shortfall of 10,374Mcf in last year's GCR filing or a change of 6,257 Mcf. Ex. 6 at 4. The year-to-year decrease is due to a large industrial customer switching to firm transportation service and projected decreases in customer additions. Id.

26. Mr. Bacon stated that the Company expected a gas under-recovery of \$4.3 million as of October 31, 2006. Ex. 6 at 8. This under-recovery is largely explained by over 2 Bcf of lower than budgeted sales and higher pipeline transportation and storage costs that were offset, in part, by lower commodity costs and higher demand credits. Id.

27. Mr. Bacon noted that in last year's GCR proceeding, the parties agreed to a settlement (approved by the Commission) which provided that for the purposes of future forecasting for the GCR, Delmarva would use the NYMEX natural gas futures index as the primary tool for determining the gas prices for its annual application. See PSC Order No. 6956 (July 11, 2006). Mr. Bacon explained that in the

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current GCR application (and supplemental application) the Company also used a blended rate, in contrast to the approved settlement, because in its business judgment the exclusive use of the NYMEX futures prices for its 2005-2006 GCR would have produced an over-recovery sufficiently significant enough to justify the filing of an interim GCR rate decrease. For the 2005-2006 GCR, the actual last day settle prices, particularly in February 2006, were lower than the Company's forecast due primarily to a very mild winter and strong gas supply despite multiple hurricanes. Ex. 6 at 14.

28. DPA's Direct Testimony. The DPA submitted the prefiled testimony of one witness, Andrea C. Crane, Vice President of Columbia Group, Inc. Ms. Crane recommended that the Company's proposed GCR rates as contained in its supplemental filing, approved by the Commission on a temporary basis pursuant to PSC Order No. 7141 (March 20, 2007), should be made permanent for the period November 1, 2006 through October 31, 2007, subject to true-up in the next GCR filing. Ex. 7 at 11.

29. Ms. Crane found that the 2006 results of the Company's hedging program was not good because ratepayers paid \$11.8 million more than they would have had the Company secured its gas supply through the NYMEX. Ex. 7 at 13. According to its fourth quarter hedging report for 2006, the Company reported that it hedged an average of 73% of its firm supply requirements for the twelve months ending December 31, 2006. Ex. 8 at 14. Nevertheless, Ms. Crane concluded that the Company's hedging decisions made in the past twelve months were not unreasonable. She noted that although the results obtained by the Company were not as favorable as they have been in previous years, the Company's actions in implementing its program were generally reasonable. Id.

30. However, Ms. Crane found that the Company's forecasts for off-system sales margins and capacity release revenues appear to be low in comparison to historical results. Further, she determined that the off-system sales margins and capacity release revenues may not comply with the methodology for sharing prescribed by the PSC. Ex. 8 at 6-7.

31. Ms. Crane observed that the Company's original filing included capacity release revenues of \$2,067,400, off-system sales margins of \$655,300, and interruptible gas transportation credits of \$930,341. The Company's supplemental filing included total demand credits of \$3,835,508, including capacity release revenues of \$2,746,333 and **off-system sales** margins of \$808,980. Ex. 8 at 15. Pursuant to PSC Order No. 5813 (Oct. 2, 2001), one hundred **percent** (100%) of margins from **capacity release, off-system sales** and swaps are to be credited to ratepayers until a total credit of \$1.7 million is reached for the 12-month period ending every June. After the \$1.7 million limit is achieved, the margins are shared between the GCR and the Company (80% to the GCR and 20% to the Company) until the following July when the cycle begins again. See PSC Order No. 5813 (Oct. 2, 2001), Attachment 'A,' Proposed Settlement at ¶2. However, based upon historical data, Ms. Crane suggested that her review of the Company's filing and supporting schedules indicated that

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all margins are being shared on an 80%/20% basis. Ex. 7 at 17. Therefore, she recommended that the Company provide information on the actual level of capacity release revenues and off-system margins it had received and that it should be required to demonstrate that it had complied with the approved sharing methodology. Id.

32. In her pre-filed testimony, Ms. Crane stated that the Company's estimated design day firm customer requirements are 173,347 Mcfs for the 2006-2007 GCR period while its firm design day supply is only 169,230 Mcfs, resulting in a shortfall of 4,117 Mcfs. In the past several years, the design day model used by the Company has produced forecasted deficits. This shortfall is currently projected to grow to 20,853 Mcfs by the 2011-2012 heating season. Ex. 7 at 17- 18.

33. Ms. Crane noted that the Company is taking several steps to address its projected capacity shortfall. On December 13, 2006, Delmarva has executed a Precedent Agreement for 25,000 Dths/day of new firm transportation service relating to the Transco Sentinel Expansion Project. This project is expected to come on-line in November 2008. Ex. 7 at 21. In addition, the Company anticipated obtaining new firm transportation service from ESNG. Id. ESNG has proposed to develop, construct, and operate new pipeline facilities that would begin in Calvert County, Maryland, cross the Chesapeake Bay, and then interconnect with ESNG's existing facilities in Sussex County, Delaware. If this project is completed, DPL could begin receiving service from Dominion's Cove Point LNG facility in late 2010 or 2011. Ex. 7 at 21-22.

34. In any event, Delmarva has signed a Precedent Agreement with ESNG for 30,000 Dths/day of firm transportation capacity. Ex. 7 at 22. In addition, Delmarva has executed a Letter Agreement with ESNG in which the Company agrees to pay up to \$2 million of pre- certification costs incurred by ESNG in the event that the ESNG project is not placed into service.

35. Based upon the Company's history, Ms. Crane determined that Delmarva would continue to meet its design day deficits over the next few years. Ms. Crane noted that the Company is exploring new supply options to address future design day deficits. She urged the Commission to continue to monitor Delmarva's design day deficit and to require Delmarva to report annually in its GCR filings on actions taken to ensure that it will be able to meet its design day requirements over the long-term. Ex. 7 at 23.

36. Ms. Crane recommended that the Commission review Delmarva's line loss factor in the future to determine if a change from the 2.5% used in this case is appropriate. Ex. 7 at 23. The 2.5% loss factor is the percentage loss factor the Company has used in the past several GCR filings. Ms. Crane noted that the actual rolling twelve-month average through June 2006 was 3.0%, while the thirty-six month average was 2.4%. Ms. Crane was confident that even if the loss factor of 2.5% used in this case was not precise, the costs resulting from the loss factor

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are trued-up annually which ensure that ratepayers will pay rates that reflect actual costs incurred by the Company in the GCR year. Ex. 7 at 24.

37. Staff's Direct Testimony. Commission Staff submitted the prefiled testimony of Funmi Jegede, Public Utilities Analyst. Ex. 8. Ms. Jegede detailed her review of Delmarva's application. She recommended that the Commission approve the changes sought by the Company to modify its current GCR factors. Ex. 8 at 11-12.

38. Ms. Jegede noted that the proposed rates, made effective November 1, 2006 on a temporary basis, were based on projected sales data and gas costs for the twelve-month period November 1, 2006 through October 31, 2007. Ms. Jegede also reviewed the Company's proposals to reconcile and true-up actual with estimated monthly Weighted Average Commodity Costs of Gas ('WACCOG') for its Large Volume Gas service ('LVG') and electing Medium Volume Gas service ('MVG') customers. Staff reviewed the natural gas demand and supply plan for this application and the strategic gas supply plan for the 6- year period 2006 through 2007 through 2011 through 2012. Ex. 8 at 2.

39. Ms. Jegede opined that she reviewed the Company's supplemental application to further decrease its charges for services rendered on or after the effective date of April 1, 2007. She testified that the Company's revised gas costs projections were actually out of band when it made its supplemental filing using actual January 2007 recovery balances for the projected GCR period. However, using its actual February adjustments for this GCR period, the Company's projections fell within the allowable band (4 1/2% and 6%). Ex. 8 at 4. In addition, Ms. Jegede reported that the Company's projected demand charges are higher than those of its prior GCR application. Ms. Jegede stated that the Company should take additional steps to reduce its fixed costs. Id.

40. Further, Ms. Jegede reported that the Company does not expect any major pipeline refunds in the applicable GCR period. Staff also found that the Company's proposed rates proposed in this proceeding (in both its original and supplemental filings) were reasonable. Consequently, Staff recommends that the Commission approve Delmarva's request to modify its current GCR factors in this proceeding.

41. Staff observed that the Company submitted its strategic gas supply plan very late (in February 2007) in this proceeding. Staff therefore recommends that the Company file its strategic gas supply plan no later than thirty (30) days after it makes its GCR filing.

42. In her prefiled testimony, Ms. Jegede cautioned that the Company's projected design day supply plan shows significant shortages over the next six-year projected GCR determination periods (2006/2007 through 2011/2012). She recommended that the Company regularly update Staff on measures taken to reduce its design day shortages and not wait until it files its next GCR filing in August 2007.

43. Ms. Jegede noted that in its current GCR filing the Company used blended rates

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derived from the prices and forecasts provided in the NYMEX, PIRA and EIA indices. Staff noted that in the last GCR proceeding, the parties agreed that blended rates would not be used; rather, only NYMEX prices would be used. However, in light of the decrease in gas prices over the period of this filing, Ms. Jegede testified that she agreed with the use of the blended rates in this instance. Ms. Jegede noted that because of the Company's use of the blended rates in this filing, an average residential heating customer using 120 Ccf per month will experience a decrease of \$16.41 or 8.7% during the 2006-2007 winter heating season. Ex. 8 at 14, citing Schedule FJ-1.

44. Ms. Jegede further recommended that an expert review Delmarva's hedging program and supply plan in the next GCR filing. She cited the continued volatile condition of the energy markets and the effects of major hurricanes on natural gas facilities in recent years as the need for a comprehensive review of the hedging program and supply plan. Ex. 8 at 5.

45. The Company's external, independent audit report regarding Delmarva's customer billing and the determination for sharing of its margins for the GCR period October 1, 2005 through September 20, 2006 was submitted on April 4, 2007. Ms. Jegede maintained that Delmarva's filing on April 7 was very late. Therefore, she recommended that in the future the Company should submit its internal and external audit reports no later than November 30 of each year, approximately two months after the close of the GCR period. Ex. 8 at 5.

46. Ms. Jegede recommended that in its next GCR filing the Company should continue to provide Staff with updates of its budget billing program and the programs it undertook to educate or inform customers on ways to mitigate the effects of gas market fluctuations. Ex. 8 at 5.

B. The Proposed Settlement.

47. The parties reported that after several discussions and protracted negotiations a Proposed Settlement agreement had been reached. The Proposed Settlement consists of 10 pages and is attached hereto as Attachment 'B.' Ex. 12.

48. Delmarva's Proposed Rates. In the Proposed Settlement, the parties also agreed to recommend Delmarva's proposed rates to the Hearing Examiner and to the Commission. In addition, the parties agreed to recommend to the Hearing Examiner and to the Commission Delmarva's proposals to: a) reconcile and true-up actual versus estimated Weighted Average Commodity Cost of Gas ('WACCOG ') assignments for sales under the Flexibly Priced Sales service to restate fuel revenue and shared margin revenue credits; and b) reconcile and true-up actual versus estimated WACCOG assignments for sales under the Large Volume Gas service and for so-called 'electing' customers taking service under the Medium Volume Gas service.

IV. DISCUSSION

49. The Commission has jurisdiction in this matter pursuant to 26 Del. C. § 303(b).

50. In this case, neither Staff nor the DPA object to the proposed GCR factors, reconciliation and true-ups, non-firm surcharge, or to the proposed tariff (non-rate) modifications.

51. As seen in the testimony and in the attached Proposed Settlement, Staff and DPA agree that the Company's proposed GCR rates, proposed reconciliation and true-ups (as corrected), proposed non-firm surcharge, and the proposed tariff (non-rate) modifications are just and reasonable. For these reasons, I find that the approval of the Proposed Settlement is in the public interest and represents a fair and reasonable resolution of this matter, and I therefore recommend that the Commission adopt and approve it.

52. I have considered all of the record evidence and, based thereon, I submit for the Commission's consideration these findings and recommendations.

V. RECOMMENDATIONS

53. In summary, and for the reasons discussed above, I propose and recommend to the Commission the following:

***3** A. That the Commission adopt as just, reasonable and in the public interest the Company's proposed rates and tariff changes (made effective on a temporary basis pursuant to PSC Order No. 7141 on March 20, 2007 with meter readings on and after April 1, 2007 until October 31, 2007 as shown below:

	GCR Demand Charge	GCR Commodity Charge
Rate Schedules		
RG, GG and GL	N/A	102.357[/ccf
Non-electing	\$9.98/Mcf of	\$8.8683/Mcf
MVG	Billing MDQ	
Electing MVG &	\$9.98/Mcf of	Varies
LVG	Billing MDQ	
Standby Service	\$9.98/Mcf of	N/A
	Standby MDQ	

B. That the Commission approve as just, reasonable, and in the public interest the Company's proposals to: a) reconcile and true-up actual versus estimated Weighted Average Commodity Cost of Gas ('WACCOG') assignments for sales under the Flexibly Priced Sales service to restate fuel revenue and shared margin revenue credits; and b) reconcile and true-up actual versus estimated WACCOG assignments for sales under the Large Volume Gas service and for so-called 'electing' customers taking service under the Medium Volume Gas service.

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54. A proposed Order, which will implement the foregoing recommendations, is attached hereto as 'Attachment A.'

Respectfully submitted,

Dated: June 13, 2007

ATTACHMENT 'B'
 PROPOSED SETTLEMENT

On this 11th day of May, 2007, Delmarva Power & Light Company ('Delmarva' or the 'Company'), the Delaware Public Service Commission Staff (the 'Staff'), and the Division of the Public Advocate ('DPA'), all of whom together are the 'Parties' or 'Settling Parties,' hereby propose a complete settlement of all issues that were raised in this proceeding as follows.

I. INTRODUCTION AND PROCEDURAL BACKGROUND

On August 31, 2006, Delmarva filed an application (the 'Initial Application') with the Delaware Public Service Commission (the 'Commission') to modify its Gas Cost Rate ('GCR') factors, effective on and after November 1, 2006, with proration, and with such revised factors to continue in effect until October 31, 2007. Delmarva also requested approval: a) to reconcile and true-up actual versus estimated Weighted Average Commodity Cost of Gas ('WACCOG') assignments for sales under the Flexibly Priced Sales service to restate fuel revenue and shared margin revenue credits; and, b) to reconcile and true-up actual versus estimated WACCOG assignments for sales under the Large Volume Gas service and for so-called 'electing' customers taking service under the Medium Volume Gas service.

On October 3, 2006, in Order No. 7039, the Commission allowed the new proposed GCR factors, reconciliation and true-ups, and the LVG and electing MVG surcharge credit to become effective on a temporary basis, subject to refund, effective with meter readings on and after November 1, 2006, with proration. The Commission's Order also assigned the matter to Hearing Examiner Ruth Ann Price, Esquire for further proceedings.

Pursuant to Order No. 7039, notice of the application, including information on how to intervene in the proceeding, was published. In addition, Delmarva provided notice to multiple agencies throughout its natural gas service territory. The Settling Parties request that the public notices be admitted into evidence as Exhibit 1.

*4 The DPA made a timely intervention in the proceeding. No other party intervened.

After discussion among the Parties and with the approval of the Hearing Examiner

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a procedural schedule was adopted. The procedural schedule established May 11, 2007 for an evidentiary hearing.

A public comment session was conducted and presided over by Hearing Examiner Price on November 29, 2006. No members of the public attended.

On February 23, 2007, Delmarva filed a mid-proceeding application to lower its GCR Clause rates effective April 1, 2007, based on its revised projections of its gas fuel revenue and purchased gas costs. According to Delmarva, continued use of the GCR rates allowed to go into effect on November 1, 2006 would lead to the Delmarva becoming 'out-of-band' (see P.S.C. Del. No. 5 -- Gas, Section XX, Leaf 36), with a possible over-collection of \$6.2 million by the end of the application period. The Commission granted Delmarva's request to lower the GCR during this proceeding by Order No. 7141, thus allowing the lowered rates to become effective on a temporary basis, subject to refund, effective with meter readings on and after April 1, 2007, with proration.

Both Staff and DPA served data requests upon Delmarva, which Delmarva responded to. The parties also engaged in the exchange of information on a more informal basis.

The DPA and Staff filed responsive testimony on or before April 13, 2007. Delmarva filed brief rebuttal testimony on April May 4, 2007.

II. SUMMARY OF THE APPLICATION

Delmarva's combined Applications proposed modifications to 2006-2007 GCR year components applicable to firm sales customers, compared with the Gas Cost Rate factors in effect for the 2005-2006 GCR year as shown below:

	2005-2006	Proposed		
	GCR	GCR	GCR	GCR
	Demand	Commodity	Demand	Commodity
Rate Schedules	Charge	Charge	Charge	Charge
RG, GG and GL	N/A	118.384[/ccf	N/A	102.357[/ccf
Non-electing MVG	\$6.20/Mcf of	\$11.0279/Mcf	\$9.98/Mcf of	\$8.8683/Mcf
	Billing MDQ		Billing MDQ	
Electing MVG and	\$6.20/Mcf of	Varies	\$9.98/Mcf of	Varies
	Billing MDQ		Billing MDQ	
LVG	\$6.20/Mcf of	Varies	\$9.98/Mcf of	Varies
	Billing MDQ		Billing MDQ	
Standby Service	\$6.20/Mcf of	N/A	\$9.98/Mcf of	N/A
	Billing MDQ		Billing MDQ	

III. SETTLEMENT PROVISIONS

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A. The parties agree that approval of Delmarva's Application, as filed, should be recommended by the Hearing Examiner and subsequently approved by the Commission. The parties agree that the proposed GCR complies with the Tariff and its approval would be in the public interest.

B. ADDITIONAL PROVISIONS:

1. The provisions of this settlement are not severable.
2. This Settlement shall not be regarded as a precedent with respect to any ratemaking or any other principle in any future case. No Party to this settlement necessarily agrees or disagrees with the treatment of any particular item, any procedure followed, or the resolution of any particular issue in agreeing to this settlement other than as specified herein, except that the Parties agree that the resolution of the issues herein taken as a whole results in just and reasonable rates.
3. To the extent opinions or views were expressed or issues were raised in the pre- filed testimony that are not specifically addressed in the Settlement, no findings, recommendations, or positions with respect to such opinions, views or issues should be implied or inferred.

*5 IN WITNESS WHEREOF, intending to bind themselves and their successors and assigns, the undersigned parties have caused this Proposed Settlement to be signed by their duly- authorized representatives.

Todd L. Goodman Delmarva Power & Light Company

By: Todd L. Goodman Print Name

Date: 5/11/07

G. Arthur Padmore Division of the Public Advocate

By: G. Arthur Padmore Print Name

Date: 5/11/07

Michael D. Sheehy Delaware Public Service Commission Staff

By: Michael D. Sheehy Print Name

Date: 05/10/07

APPENDIX A
 RATES AND CHARGES

Effective with meter readings on and after November 1, 2006, with proration:

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	GCR Demand Charge	GCR Commodity Charge
Service Classifications		
RG, GG, and GL	N/A	106.972 [/ccf
Non-Electing MVG	\$9.98/Mcf of	\$9.3298/Mcf
	Billing MDQ	
Electing MVG and LVG	\$9.98/Mcf of	Varies
	Billing MDQ	
Standby Service	\$9.98/Mcf of	N/A
	Billing MDQ	
Electing MVG and LVG		
Surcharge Credit	N/A	\$0.7199/Mcf

APPENDIX A RATES AND CHARGES

Effective with meter readings on and after April 1, 2007, with proration:

	GCR Demand Charge	GCR Commodity Charge
Service Classifications		
RG, GG, and GL	N/A [/ccf	102.357 [/ccf
Non-Electing MVG	\$9.98/Mcf of	\$8.8683/Mcf
	Billing MDQ	
Electing MVG and LVG	\$9.98/Mcf of	Varies
	Billing MDQ	
Standby Service	\$9.98/Mcf of	N/A
	Billing MDQ	
Electing MVG and LVG		
Surcharge Credit	N/A	\$0.7199/Mcf

FOOTNOTES

FN1 The Public Comment Hearing held on November 29, 2006 was a jointly held session with the public comment sessions for PSC Docket No. 06-284, Delmarva's base rate case, entitled, In The Matter Of The Application Of Delmarva Power & Light Company For A Change In Natural Gas Base Rates, filed on August 31, 2006 and PSC Docket No. 06-283, Delmarva's environmental surcharge rider rate case, denominated

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as In The Matter Of The Application Of Delmarva Power & Light Company For A Change In The Gas Environmental Surcharge Rider Rate, filed on August 31, 2006. No members of the public attended the sessions for either of these cases.

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H

Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of National Fuel Gas Distribution Corporation for Gas Service.

04-G-1047

New York Department of Public Service

January 19, 2006

December 30, 2005

SUMMARY

Filed Session of January 18, 2006 Approved as Recommended and so Ordered

FROM: OFFICE OF GAS AND WATER - GAS RATES

National Fuel Gas Distribution Corporation filed revisions to its gas tariff implementing the first stage of a two-year rate plan pursuant to July 22, 2005 order in Case 04-G-1047.

RECOMMENDATION: Staff recommends that the amendments listed in Appendix I be allowed to become effective on a permanent basis on January 20, 2006.

THE COMMISSION

National Fuel Gas Distribution Corporation (NFG or the company) filed tariff amendments (see Appendix I) in compliance with the Order Establishing Rates and Terms of Two-Year Rate Plan issued on July 22, 2005 in Case 04-G-1047 (July 22 Order). Staff reviewed the amendments and finds that they comply with the July 22 Order. Therefore, the amendments should be allowed to become effective on a permanent basis on January 20, 2006.

BACKGROUND

On July 22, 2005, the Commission adopted a rate plan for NFG, which provides for a total revenue requirement increase of \$21 million. Available credits will mitigate the effect of the delivery rate increase on customers' bills for the term of the two-year rate plan and result in a reduction of \$15 million to actual annual bills when compared to bills based upon the previous rate plan's delivery rates. The plan also includes provisions for maintaining safety, ensuring continued high levels of customer service and providing help to low income customers to pay their gas bills.

The Commission directed NFG to file, effective August 1, 2005 on a temporary basis, tariff amendments as necessary to implement the requirements of the July 22 Order. In addition, the Commission directed the company to serve copies of the

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compliance filing on all parties in this proceeding, allowing ten days for comments. According to the July 22 Order, the amendments filed by NFG shall not become effective on a permanent basis until approved by the Commission.

On July 29, 2005, the company filed tariff revisions to its gas tariff, P.S.C. No. 8, in compliance with the July 22 Order. The amendments are briefly described in Appendix II.

DISCUSSION

Staff has reviewed the company's filing and finds that the tariff amendments properly reflect the provisions of the July 22 Order. The amendments include language necessary to effectuate the increase in delivery revenues, as well as rate design and other changes described in the rate plan. No party has commented on the changes, and Staff believes the tariff amendments should be approved on a permanent basis.

It is recommended that the amendments listed in Appendix I be allowed to become effective on a permanent basis on January 20, 2006.

Respectfully submitted,

MICHAEL SALONY Utility Supervisor

VICKI M. MASSARONI Utility Analyst 2

Reviewed by:

JUSTYN P. BATES Assistant Counsel Office of General Counsel

Approved by:

MICHAEL J. SCOTT Chief, Gas Rates Office of Gas and Water

APPENDIX I

SUBJECT: Filings by NATIONAL FUEL GAS DISTRIBUTION CORPORATION

Amendments to Schedule P.S.C. No. 8 -- Gas

Original Leaves Nos. 209.1, 243.1, 267.1

First Revised Leaves Nos. 120, 122, 137, 148.5, 148.8, 148.9, 160, 171, 222.1, 242, 243, 250, 252, 253, 266.1.1, 304

Second Revised Leaf No. 126, 129, 130, 131, 132, 134, 140, 197, 231, 234, 235, 236, 248, 257, 266.2, 282, 284, 286, 299

Third Revised Leaves Nos. 24, 74.2, 94, 127, 128, 139, 148.4, 151, 159, 161,

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163, 179, 230, 266.3, 278, 279, 280, 281, 283, 285, 296

Fourth Revised Leaves Nos. 3.1, 81, 133, 148.3, 156.2, 164, 173, 174, 209, 220, 225, 237, 255, 258, 259, 266.1, 266.5, 270.1, 295

Fifth Revised Leaf No. 83, 86, 141, 148, 148.2, 148.6, 183, 213, 217, 218, 260, 263, 267, 277

Sixth Revised Leaves Nos. 12, 82, 84, 138, 157, 186, 190, 205, 210, 219, 221, 224, 262, 266, 269

Seventh Revised Leaves Nos. 2, 74, 148.7, 149, 156.1, 175, 184, 206, 207, 266.4, 275

Eighth Revised Leaves Nos. 152, 153, 187, 189

Ninth Revised Leaf No. 150, 158, 165, 211, 276

Tenth Revised Leaf No. 154, 270

Twelfth Revised Leaf No. 271

Thirteenth Revised Leaf No. 222

Fifteenth Revised Leaf No. 3

Revenue Tax Statement No. 33

Received: July 29, 2005

Effective: August 1, 2005

Sixth Revised Leaf No. 213

Seventh Revised Leaf No. 224

Received: August 10, 2005

Effective: August 11, 2005

Sixteenth Revised Leaf No. 3

Received: September 14, 2005

Effective: September 15, 2005

APPENDIX II NATIONAL FUEL GAS DISTRIBUTION CORPORATION'S TARIFF CHANGES PURSUANT TO THE COMMISSION'S JULY 22, 2005 ORDER

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As described in the Commission's July 22, 2005 order in Case 04-G-1047, NFG has made tariff changes as follows:

RATE INCREASE

The rate increase is generally recovered from the minimum charges, with the exception of S.C. No. 3 (General Service) and S.C. No. 13 TC4.1 (Large Volume Transportation) customers, from whom 50% of the allocated increase will be recovered from the usage rate blocks and 50% from the minimum charge.

RATE UNBUNDLING

The gas commodity charges are unbundled into charges for gas supply and a merchant function charge (MFC). The MFC will be calculated monthly to reflect changes in gas costs. An unbundled billing service charge is applied to bills rendered by the company for delivery and/or sales service.

RECOVERY OF LOST REVENUES DUE TO INCREASES IN CUSTOMER MIGRATION

Each year, for the 12 months ended July 31, the company will calculate lost MFC and billing revenues resulting from customers migrating from sales to transportation service. Revenues are lost if, as a result of customers migrating from sales to transportation service, there has been a decline in imputed billing and MFC activity based on weather normalized volumes. The imputed billing service activity will be 5,680,162 bills. The imputed MFC volumes will be 44,324,153 Mcf for S.C. No. 1 and 8,431,124 Mcf for S.C. No. 3. The lost billing revenues and lost MFC revenues will be recovered through the Delivery Adjustment Charge in the delivery rates of S.C. Nos. 1 and 3 customers for the 12 months beginning January 1 of each year. The company will file the lost revenue calculation with its annual gas cost reconciliation filing.

The determination of lost billing and lost MFC revenue will be based on actual migrated customers and actual weather normalized customer consumption. The actual migration activity will be determined by summing all volumes and bills associated with customers migrating from utility sales service and billing service commencing August 1, 2005.

ELIMINATION OF BACK-OUT CREDITS

A "back-out credit" is a credit provided to a customer or marketer that is designed to remove charges for utility services that are provided by the marketer. Back-out credits were adopted as a temporary proxy until fully-developed unbundled rates could be established. The unbundled rates have been established and, accordingly, NFG's existing Billing Back-Out Credit and Competition Back-Out Credit will be terminated.

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ELIMINATION OF BILL CREDIT AND HIECA CREDIT

Under the terms of the company's previous rate plans, an annual bill credit in the aggregate amount of \$5 million was applied to customers' bills. The bill credit was designed to continue until it was replaced through the modification of base delivery rates or otherwise eliminated in a subsequent proceeding. NFG has eliminated the bill credit.

Under its prior rate plan, NFG applied a credit to customer rates equal to the expense level formerly reflected in rates to support costs generated by the terminated Home Insulation and Energy Conservation Act (HIECA) program. HIECA Credit was eliminated in the development of base rates calculated in this proceeding and, therefore, the HIECA bill credit is no longer necessary.

ASSISTANCE FOR LOW INCOME RESIDENTIAL CUSTOMERS

NFG modified its Low-Income Residential Assistance Program by increasing the rate discount per eligible customer from \$100 annually (\$8.33 per month) to \$170 annually (\$14.17 per month). This is the first-phase change to the program. Other changes are scheduled later in 2006.

STATE INCOME TAX CREDITS

The company collects State Income Taxes (SIT) via the Revenue Tax Surcharge (RTS). The difference between the SIT rate and the RTS resulted in SIT overcollections. The remaining overcollection will be returned by the company to customers through bill credits. For S.C. No. 1 (Residential) and S.C. No. 3, the bill credits will be applied to the minimum charges. For S.C. No. 10 (Cogeneration), S.C. No. 13 (Transportation), S.C. No. 16 (Large Cogeneration Transportation) and S.C. No. 17 (Cogeneration Transportation) customers, the credits will be allocated on a volumetric basis.

LOST AND UNACCOUNTED FOR GAS

NFG will revise its factor of adjustment ratio from 2.0% to 1.95% effective September 1, 2005. Effective September 1, 2006, the factor of adjustment will be further reduced to 1.90%.

MILLENNIUM FUND SURCHARGE

The February 14, 2000 order in Case 99-G-1369 (the Millennium Order) directed the establishment of a mechanism to replace the FERC Gas Research Institute (GRI) surcharge on interstate pipeline rates. A 1998 FERC order established a schedule to phase out the GRI surcharge. The GRI surcharge was adopted by FERC to support broad-based gas-related research and development. The Millennium Order established a surcharge on firm retail gas rates (the Millennium Fund Surcharge) that in-

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creased as the FERC GRI surcharge was decreased. NFG will reduce its Millennium Fund Surcharge from \$.0203/Mcf to \$.0091/Mcf, which will continue to fund the "Millennium Fund" for research and development programs.

BUSINESS DEVELOPMENT RATES

The Business Development Rates (BDR) is an economic development rate discount program provided to business customers who qualify under criteria designed to promote the development of new and expanding businesses. The company will extend its BDR applicable under S.C. No. 3 -- General, S.C. No. 13M -- Monthly Metered Transportation Service and S.C. No. 13D -- Daily Metered Transportation Service for an additional 5 years. The company will add the following qualifying Standard Industrial Codes to its BDR rider: 01-14 (Agriculture, Forestry, Fishing and Mining), 64 (Insurance Agents, Brokers and Services) and 73 (Business Services).

The Empire Development Zone (EDZ) is an economic and business development rate discount offered to applicants located in EDZs designated by the State. The EDZ will continue as currently structured.

CHANGES TO TRANSPORTATION SERVICES

Large transportation customers have had the option of monthly metered service on a "stand alone" basis. Stand-alone monthly service will be phased out to reflect changed circumstances since this service was developed many years ago. Current stand-alone monthly customers have the choice of selecting either the Supplier Transportation, Balancing and Aggregation (STBA) service or the Daily Metered Transportation and balancing services

S.C. No. 19 - Supplier Transportation, Balancing and Aggregation Service (STBA)

To facilitate these changes, STBA will be modified as follows:

1. Imbalance charges to be included in rates are to be determined based on capacity to meet a 62 Heating Degree Day requirement.
2. Capacity assignment rules will not change and the capacity requirements will remain based on the standard to meet a 62 Heating Degree Day.
3. New balancing charges will go into effect on September 1, 2005.
4. Because all Monthly Metered Transportation customers will now be served under the STBA program, and the majority of large volume transportation customers (annual throughput greater than 25,000 Mcf) were transportation customers prior to aggregation service, transition cost charges associated with the company's contracted pipeline capacity will not be included in large volume customer rates.

Standard Monthly Metered Transportation (CBA -- Customer Balancing and Aggrega-

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tion) Service Phase-Out

Meters capable of real-time readings had previously been installed for most of the company's largest customers with annual consumption exceeding 55,000 Mcf (S.C. No. 13 -- TC3, 4, and 4.1).

Real-time meters will be installed for the remaining large-volume transporters. Customers in this category with more than 15 meters per account will be permitted to opt out of the real-time measurement requirement. Where these customers opt for real-time measurement, the company will investigate alternative metering configurations to minimize installation and operating costs. This decision was required by September 1, 2005 to avoid being charged the increased standard STBA service rates. Notwithstanding the September 1, 2005 date, customers had 30 days to make a decision after the presentation of alternative metering options by the company. This is a requirement of service whether those customers migrate to Daily Metered Transportation service or not.

Any firm transportation customer with annual usage between 5,000 and 55,000 Mcf (S.C. No. 13 -- T.C. 1.1 and 2.0) may volunteer for real-time meter installation and Daily Metered Transportation Service. However, once installed, the installation must be maintained similar to the larger volume (greater than 55,000 Mcf annually) customers. The decision was required by September 1, 2005 to avoid being charged the higher standard Monthly Metered Transportation STBA balancing service rates.

All other delivery rates and imbalance charges associated with Monthly Metered Transportation STBA service will apply to CBA service.

The gas costs included in rates to be charged to Monthly Metered Transportation customers electing Daily Metered Transportation service during the transition from monthly to daily service shall be equal to the current charges included in the Monthly Metered Transportation CBA service rates (\$.0378/Mcf for S.C. No. 13 -- T.C. 4.0 and \$.0928/Mcf for all other S.C. No. 13 customers. This lower transition rate shall cease on April 1, 2006. The customer was required to make the election by September 1, 2005 and convert to Daily Metered Transportation service by April 1, 2006 to avoid being charged the increased standard STBA service rates.

In all cases, customers are responsible for data communication expenses related to providing meter data to the company on a real-time basis.

S.C. No. 13D - Daily Metered Transportation Service

1. Real-time metering is required for S.C. No. 13 Daily Metered Transportation service.

2. Daily balancing band widths will be 10% year round, but the end of month band width will be 5% from November through March of each year and 10% for the rest of

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the year.

LOCAL PRODUCTION

NFG permits the use of local production to replace a portion of the upstream pipeline capacity required to sustain STBA service so long as the local production output is monitored electronically as is pipeline-delivered gas. Since electronic monitoring is a costly requirement that deters the use of local production for STBA service, the company previously accepted a portion of local production without electronic monitoring (65% of flowing supplies) as a substitute for the STBA upstream capacity requirement. The company has increased the 65% allowance to 100% of projected monthly volume.

PURCHASE OF ACCOUNTS RECEIVABLE PROGRAM

NFG will offer a three-year Purchase of Accounts Receivable (POR) Pilot Program to ESCOs who are authorized to provide gas commodity service in its territory. Under the POR program, the company will provide a consolidated bill to ESCO customers at the same time the company bills its bundled sales customers for each of the company's 21 billing cycles per month. For each billing cycle, NFG will purchase the ESCO's receivables 23 days after the ESCO's customer is billed, at a price that is discounted by 2.6%, in the case of residential customers, and 0.71% for commercial and industrial customers, than the face amount of the receivable. The company's purchase of the accounts receivable is without recourse. The POR program will be available on the company's firm transportation customer accounts that receive a consolidated bill from NFG and include gas commodity service provided by an ESCO. NFG is not required to offer additional utility consolidated billing options to ESCOs apart from those available through the POR Pilot. Dual billing and ESCO-consolidated billing options remain available.

CAPACITY RELEASE CREDITS AND OFF-SYSTEM SALES

Customers will benefit from capacity release or off-system sales. The first \$1 million of savings from interstate pipeline and storage **capacity releases** and **off-system sales** will be applied to the Cost Mitigation Reserve (CMR). Eighty-five **percent** of any remaining **capacity release** savings and/or net revenue from **off-system sales** will be accumulated. Such accumulated amounts will be distributed to the company's customers during each subsequent five-month period beginning in November and ending in March, through the gas adjustment clause, and 15% of such savings and revenues will be retained by the company.

END OF DOCUMENT

▷

Re Vectren Energy Delivery of Ohio, Inc.
Case No. 02-220-GA-GCR

Ohio Public Utilities Commission
June 14, 2005

APPEARANCES: McNees, Wallace & Nurick LLC, by Gretchen J. Hummel and Samuel C. Randazzo, 21 East State Street, 17th Floor, Columbus, Ohio 43215-4228, and Robert E. Heidorn and Ronald E. Christian, Vectren Utility Holdings Inc., 20 N. W. Fourth Street, Evansville, Indiana 47708, on behalf of Vectren Energy Delivery of Ohio, Inc. (Vectren). Janine Migden-Ostrander, Ohio Consumers' Counsel, by Ann Hotz and Joseph P. Serio, Assistant Consumers' Counsel, 10 West Broad Street, 18th Floor, Columbus, Ohio 43215, on behalf of the residential customers of Vectren. Jim Petro, Attorney General of Ohio, by Werner L. Margard and Thomas G. Lindgren, Assistant Attorneys General, 180 East Broad Street, Columbus, Ohio 43215-3793, on behalf of the Commission staff.

Before Schriber, chairman, and Fergus, Jones, Mason, and Rogers, Jr., Commissioners.

BY THE COMMISSION:

OPINION AND ORDER

***1** The Public Utilities Commission of Ohio (Commission), having considered the testimony and all other evidence presented in this matter and relevant provisions of the Revised Code and Chapter 4901:1-14, Ohio Administrative Code (O.A.C.), hereby issues its Opinion and Order.

OPINION

I. INTRODUCTION

Pursuant to Section 4905.302, Revised Code, the Commission was directed to

promulgate a purchased gas adjustment clause to be included in the schedules of gas and natural gas companies subject to the jurisdiction of the Commission. As a result, the Commission established Chapter 4901:1-14, Ohio Administrative Code (O.A.C.), [FN1] which is designed to separate the cost of gas from all other costs incurred by a gas or natural gas company subject to the jurisdiction of this Commission, and to provide for each company's recovery of such costs. Section 4905.302, Revised Code, further directs the Commission to establish investigative procedures, including periodic reports, audits, and hearings to examine the arithmetic and accounting accuracy of the gas costs reflected in the company's gas cost recovery (GCR) rates, and to review each company's production and purchasing policies and their effect upon these rates.

Vectren acquired the customer accounts and gas assets of The Dayton Power & Light Company (DP&L) on November 1, 2000. [FN2] Vectren is a natural gas company as defined by Section 4905.03(A)(6), Revised Code. Accordingly, Vectren is a public utility as set forth in Section 4905.02, Revised Code, and is, therefore, subject to Commission jurisdiction under Section 4905.302, Revised Code.

Pursuant to Rule 4901:1-14-07(A), O.A.C., the Commission caused an audit of Vectren to be conducted. The financial portion of the audit investigated Vectren's GCR rates effective during the financial audit period, November 1, 2001, through October 30, 2002. Deloitte & Touche (D&T or financial auditor) conducted the financial audit and filed its audit report on August 15, 2003 (Comm.-Ord. Ex. 1). Liberty Consulting Group (Liberty or m/p auditor) conducted the management/performance (m/p) audit of Vectren for the audit period of November 1, 2000, through October 31, 2002. [FN3] Liberty filed its m/p audit report with the Commission on August 15, 2003 (Comm.-Ord. Ex. 2).

Pursuant to Rule 4901:1-14-08(A), O.A.C., and by entry issued September 18, 2002, and as amended by entry issued September 25, 2002, this matter was scheduled for a hearing to commence on September 16, 2003. On March 7, 2003, the Ohio Consumers' Counsel (OCC) filed a motion to intervene in this proceeding on behalf of Vectren's residential consumers. OCC's request was granted by entry issued March 27, 2003. On August 19, 2003, Vectren filed a motion for a continuance of the hearing. Vectren's request to continue the hearing was granted by entry issued August 27, 2003. Accordingly, the hearing was rescheduled to commence on November 20, 2003. Vectren filed, as late-filed exhibits, its proofs of publication for this proceeding as required by Rule 4901:1-14-08(C), O.A.C., on December 9 and 12, 2003, and January 16, 2004 (Vectren Exs. 5, 5-A and 5-B, respectively).

*2 Vectren requested and was granted permission for Robert E. Heidorn and Ronald E.

Christian to appear pro hac vice before the Commission in this proceeding by entry issued November 7, 2003. Vectren filed the direct testimony of its witnesses: Jerrold L. Ulrey (Vectren Exs. 1 and 2), Perry M. Pergola (Vectren Ex. 3), and Adam M. Miller (Vectren Ex. 4) on November 4, 2003. Vectren also filed the rebuttal testimony of Mr. Ulrey (Vectren Ex. 6) on December 4, 2003. On November 13, 2003, OCC filed the direct testimony of Richard W. LeLash (OCC Ex. 1). The hearing commenced, as rescheduled, on November 20, 2003, and testimony was taken on November 20 and 21, and December 8, 2003. Initial briefs were filed by Vectren, OCC and staff on January 27, 2004, and reply briefs were filed on February 11, 2004.

II. MOTION TO STRIKE

On February 11, 2004, Vectren filed a motion to strike: (a) portions of both the m/p audit and the direct testimony of OCC's witness, (b) staff's post hearing briefs in whole or in part, and (c) portions of OCC's initial brief. Vectren made earlier motions to strike the identified sections of the m/p audit report and OCC's witness's testimony at the hearing and they were denied. Inasmuch as a ruling on the February 2004 motion to strike has bearing on what evidence and arguments we consider in this proceeding, we will address it first. OCC and staff filed memoranda contra the February 2004 motion to strike and Vectren filed replies thereafter.

We will first address Vectren's renewed request to strike portions of the m/p audit report and portions of the direct testimony of OCC's witness. Vectren correctly recognizes that it originally moved to strike the various portions of those two documents during the hearing and that the examiner denied those motions (Tr. I, 14-35; Tr. II, 95-103). The proper mechanism to seek formal Commission review of attorney examiner rulings is an interlocutory appeal pursuant to Rule 4901-1-15, O.A.C. Interlocutory appeals must be filed within five days after the ruling is issued. Vectren did not do so and, therefore, Vectren's renewed motion to strike portions of the m/p audit report and portions of the direct testimony of OCC's witness is denied. Accord, In the Matter of the Joint Application of Bell Atlantic Corporation and GTE Corporation for Consent and Approval of a Change in Control, Case No. 98-1398- TP-AMT, Opinion and Order at 59 (February 10, 2000) and Entry on Rehearing at 12-13 (April 6, 2000).

We now turn to Vectren's arguments about staff's and OCC's briefs. Vectren contends that staff's initial and reply briefs should be stricken in their entirety because, as a matter of law, the briefs have no legal status in this proceeding. Vectren argues that, pursuant to Section 4901.16, Revised Code, [FN4] staff must present any information acquired by it in a report to the Commission or when called upon to testify in any court or proceeding of the Commission. Vectren posits that staff has not presented a report or testimony in this proceeding. Vectren contends that, as a

matter of law, staff's post hearing briefs have no legal status in this proceeding and the Commission is, therefore, precluded from considering staff's briefs as a basis for any decision. Vectren concludes that, since staff's briefs are neither a report nor testimony, staff's briefs must be stricken from the record.

*3 The Commission believes that Vectren has misinterpreted the intent of Section 4901.16, Revised Code. Pursuant to Rule 4901:1-14-07, O.A.C., Liberty conducted the m/p audit as the agent of the Commission, not an agent of the Commission staff. Liberty filed its m/p audit report, as required, pursuant to Section 4901.16, Revised Code. As permitted by Section 4903.02, Revised Code, the staff was another party that participated in this proceeding, like the other parties. Staff chose not to sponsor testimony, as was within its prerogative. Staff was permitted to examine the witnesses and to argue its position on the issues. Section 4901.16, Revised Code, simply does not apply in this circumstance to preclude staff's briefs. Additionally, the briefs are merely each party's attempt to persuade the Commission based on each party's perception of the evidence presented. Briefs filed in a Commission proceeding are not evidence like the testimony taken and/or documents admitted at the hearing. In their briefs, staff and OCC have merely summarized their respective positions in this matter, referencing the relevant evidence admitted at hearing. The Commission has an obligation to rely on the evidence admitted into the record, not any party's brief, to justify its conclusions. For these reasons, Vectren's request to strike staff's post-hearing briefs in their entirety is denied.

Next, Vectren requests that sections of staff's post-hearing brief be stricken in regards to: (1) Vectren's forecasting methodology and staff's recommended disallowances (pages 6-13, 17-18); and (2) the existence and unbid nature of the agreement between Vectren and ProLiance Energy LLC (ProLiance) and staff's recommended disallowances (pages 15-16, 17-18). Similarly, Vectren requests to strike those sections of OCC's initial brief that focus on: (1) the fact that Vectren/ProLiance agreement is an unbid contract and OCC's recommended associated disallowance (page 2, first bullet point and pages 3-12, 50-51); and (2) Vectren's use of a reserve margin, the consequential excess capacity and OCC's recommend associated disallowance (page 3, last bullet point and pages 17-35). Vectren argues that these issues were subjects of the company's long-term forecast reports (LTFRs), which have previously been ruled on by the Commission and, thus, the doctrines of res judicata and collateral estoppel preclude relitigation here. More specifically, Vectren's first LTFR case was its 2000 LTFR (filed in Case No. 00-120-GA-FOR, In the Matter of the Long-Term Forecast Report of Vectren Energy Delivery of Ohio, Inc. and Related Matters (00-120), on December 8, 2000, as supplemented on February 8, 2001) in which it essentially used the LTFR methodology inherited from DP&L. Vectren's 2000 LTFR case, 00-120, was subsequently consolidated with DP&L's gas cost recovery (GCR) proceeding, Case No. 00-220-GA-GCR (00-220), In the Matter of the Regulation of the Purchased Gas Adjustment Clause Contained Within the Rate Schedules of The Dayton Power and Light Company and Related Matters (00-220). The Commission issued

the Order in 00-120/00-220 on September 25, 2001, essentially adopting the agreements filed by the parties to those proceedings (DP&L, Vectren, OCC and the staff). Vectren's 2001 LTFR was filed on June 1, 2001, in Case No. 01-320-GA-FOR, In the Matter of the Long-Term Forecast Report of Vectren Energy Delivery of Ohio, Inc. and Related Matters (01-320) and closed sua sponte on October 4, 2001. Likewise, Vectren's 2002 LTFR was filed on June 28, 2002, in Case No. 02-120-GA-FOR, In the Matter of the Long-Term Forecast Report of Vectren Energy Delivery of Ohio, Inc. and Related Matters (02-120), and closed sua sponte on August 22, 2002. Vectren contends that concerns as to the reasonableness of Vectren's 2000-2002 LTFRs were decided when the Commission approved the stipulations in 00-120/00-220 and sua sponte closed the 2001 and 2002 LTFR cases. Therefore, Vectren believes that staff and OCC are foreclosed from challenging the areas cited by Vectren. Also, Vectren believes that, as a result of 00-120, OCC and staff have endorsed a forecast with no propane usage, the practice of incorporating a reserve margin, and the fact that Vectren would perform gas supply management with assistance from ProLiance via an asset management services agreement.

*4 Staff argues that neither 00-120 nor the 2001 and 2002 LTFR cases established the reasonableness of the LTFRs, the five percent reserve margin or the asset management services agreement, nor did staff agree with those items in those dockets. As a result, staff contends that the doctrines of res judicata and collateral estoppel do not estop the Commission from addressing those issues here. OCC agrees and also states that the prudence of gas procurement issues (such as the appropriate level of a reserve margin and the means by which a local distribution company (LDC) manages its assets) are not reviewable in a LTFR case; they are GCR issues. OCC acknowledges that gas procurement decisions may be based on a forecast, but they, themselves, are not the forecast. Moreover, OCC does not agree that the stipulation in the 2000 LTFR proceeding (an agreement that the 2000 LTFR met the statutory requirements of Section 4935.04, Revised Code) [FN5] is tantamount to an endorsement of a forecast of no propane usage, the practice of incorporating a reserve margin, and the fact that Vectren would perform gas supply management with assistance from ProLiance via an asset management services agreement.

As to Vectren's claims that the issues regarding Vectren's use of its propane inventory, implementation of a five percent reserve margin and the company's design day criteria were decided as a part of the company's LTFRs and are, therefore, precluded from further consideration as a part of this proceeding, the Commission concludes that Vectren has misinterpreted the intent and purpose of Section 4935.04, Revised Code. Section 4935.04, Revised Code, requires Vectren and other gas and natural gas companies in Ohio to annually file a LTFR. Since the inception of Section 4935.04, Revised Code, the Commission has recognized the purpose and inter-relationship of the LTFR and the GCR audits. The purpose of the LTFR, as announced in Section 4935.04, Revised Code, is to require energy utilities to prospectively plan for a sufficient supply based on projected demand and to

demonstrate that such a process has been adequately implemented by the reporting utility. The LTFRs are primarily for the utilities' planning purposes.

Section 4935.04(F), Revised Code, specifically limits the Commission's review of each reporting utility's LTFR and requires us to determine if:

(1) All information relating to current activities, facilities agreements, and published energy policies of the state has been completely and accurately represented;

(2) The load requirements are based on substantially accurate historical information and adequate methodology;

(3) The forecasting methods consider the relationships between price and energy consumption;

(4) The report identifies and projects reductions in energy demands due to energy conservation measures in the industrial, commercial, residential, transportation, and energy production sectors in the service area;

(5) Utility company forecasts of loads and resources are reasonable in relation to population growth estimates made by state and federal agencies, transportation, and economic development plans and forecasts, and make recommendations where possible for necessary and reasonable alternatives to meet forecasted electric power demand;

***5** (6) The report considers plans for expansion of the regional power grid and the planned facilities of other utilities in the state;

(7) All assumptions made in the forecast are reasonable and adequately documented.

Pursuant to Section 4905.302, Revised Code, and Rule 4901:1-14-07, O.A.C., the Commission performs audits to determine, among other things, if a gas or natural gas company has acted unreasonably or imprudently with its gas procurement policies and/or practices. Vectren is correct that the subject matter of the LTFR pursuant to Section 4935.04, Revised Code, overlaps the issues raised in a GCR audit pursuant to Section 4905.302, Revised Code, but the purpose and focus of each proceeding is

different. In accordance with Section 4905.302, Revised Code, and Rule 4901:1-14-07, O.A.C., the audit can evaluate a gas utility's procurement policies and practices, including its capacity, reserve margin, and use of stored inventory. Thus, while Vectren's use of a reserve margin, its propane inventory and design-day criteria were part of its long-term planning in LTFR, which the Commission found in 00-120 to substantially comply with the requirements of Section 4935.04, Revised Code, the prudence and reasonableness of the effect of such decisions on Vectren's gas procurement policies were not and have not been evaluated in the LTFR proceedings. The appropriate proceeding for review of Vectren's gas procurement policies and practices is the GCR audit. Thus, we do not agree that res judicata or collateral estoppel apply in this situation.

In addition, we would be remiss if we did not point out that the 2000 LTFR did not include any specific reserve margin, although it did reference the concept of a reserve margin. In that proceeding, staff did not endorse and we did not evaluate or approve Vectren's decision to implement a five percent reserve margin. Similarly, we conclude that we did not evaluate or approve Vectren's decision to perform gas supply management with assistance from ProLiance via an asset management agreement. In fact, in the June 28, 2001 stipulation in 00- 120/00-220 (at page 4-5), Vectren, OCC and staff agreed that:

The next management performance audit will examine, among other things, the reasonableness of any level of compensation [Vectren] receives for its capacity. This review will focus on the market value of this capacity by examining any and all factors, information or documentation and other considerations influencing purchases, sales or other transactions and related terms and conditions as may be relevant in determining the reasonableness of VEDO's treatment of capacity Any determination regarding the above issues in future proceedings shall be based upon facts and circumstances relevant to issues that exist during the time period covered by such future regulatory proceedings and any agreements subsequent to this stipulation reached by the parties regarding these issues.

Moreover, the Commission in 00-120/00-220 specifically acknowledged that the 00-220 m/p auditor's recommendations as to Vectren were outside the audit period. [FN6] The Order (at page 12) states: 'The Commission recognizes that, although the GCR auditors included recommendations regarding Vectren, such findings are beyond the GCR audit period and provided only to put the Commission on notice about potential concerns.' Thus, the Commission finds that the Order in 00-120/00-220 clearly delayed consideration of the Vectren/ProLiance agreement until this m/p audit. For this reason, we find all aspects of the Vectren/ProLiance agreement are appropriate issues to be addressed by the parties and are properly before the Commission as a part of this proceeding. For all of these reasons, Vectren's motion to strike portions of the staff and OCC briefs, in relation to propane usage, the practice of

incorporating a reserve margin, and the Vectren/ProLiance agreement, are denied.

III. THE APPLICABLE LAW

*6 Section 4905.302, Revised Code, entitles natural gas companies to recover all actual gas costs unless there is sufficient evidence to support a Commission finding of an arithmetic error, imprudence, or unreasonableness in the company's gas procurement practices and policies. Throughout the financial and m/p audit periods, Section 4905.302(E), Revised Code, [FN7] stated:

The commission shall not at any time prevent or restrain such costs as are distributable under this section from being so distributed, unless the commission has reason to believe that an arithmetic or accounting inaccuracy exists with respect to such a distribution or that the company has not accurately represented the amount of the cost of a special purchase, or has followed imprudent or unreasonable procurement policies and practices, has made errors in the estimation of cubic feet sold, or has employed such other practices, policies, or factors as the commission considers inappropriate.

Section 4905.302(E), Revised Code, provides the basis under which a natural gas company can be prohibited from collecting its gas costs. Accord, In the Matter of the Purchased Gas Adjustment Clause Contained Within the Rate Schedules of Ohio Cumberland Gas Company and Related Matters, Case No. 02-216- GA-GCR (April 23, 2003).

However, when deciding whether the company has engaged in imprudent or unreasonable or inappropriate policies or practices, additional analysis is required. Vectren cited to several prior Commission proceedings in which the Commission considered the prudence and reasonableness of utility activity. In 1980, the Commission concluded that the reasonableness of decisions made by utility management involved the following evaluation:

One area encompasses the facts and circumstances known or reasonably anticipated at the time the decision was made and whether such facts and circumstances were taken into proper consideration in the decision-making process. A second area involves the inquiry of whether any intervening circumstances occurred or facts become known which impacted the initial decision's results, whether such intervening factors caused or should have caused management to re-think the initial decision, and whether any action or nonaction in light of the intervening factors was

appropriate. A third area is an examination of the actual results achieved by virtue of the decision.

In the Matter of the Regulation of the Fuel Cost Adjustment Clause Contained within the Rate Schedules of the Ohio Power Company and Related Matters, Case No. 79-234-EL-FAC (Subfile A), Entry on Rehearing (October 15, 1980). Additionally, in that same decision, the Commission noted that the weight to be afforded each area will vary on an issue-by-issue basis, depending on the type of decision made and how long ago it occurred.

In 1986, the Commission stated that an assessment of the prudence of utility decisions should be conducted under the following guidelines:

(1) There should exist a presumption that the decisions of utilities are prudent.

★7 (2) The standard of reasonableness under the circumstances should be used.

(3) Hindsight should not be used in determining prudence, although consideration of the outcome may legitimately be used to overcome the presumption of prudence.

(4) Prudence should be determined in a retrospective, factual inquiry.

In the Matter of the Regulation of the Purchased Gas Adjustment Clause Contained Within the Rate Schedules of Syracuse Home Utilities Company, Inc. and Related Matters, Case No. 86-12-GA-GCR, Order at 10 (December 30, 1986). We find that these decisions are appropriate in consideration of this matter.

IV. FINANCIAL AUDIT REPORT AND THE COMMISSION CONCLUSION THEREON

Pursuant to the entry issued September 18, 2002, and Rule 4901:1-14-07(C), O.A.C., D&T filed its Certificate of Accountability on August 15, 2003. The Certificate of Accountability affirms that D&T examined Vectren's GCR reports which support the GCR rates from November 2001 through October 30, 2002 (Comm.- Ord. Ex. 1). D&T concluded that Vectren fairly determined, in all material respects, the GCR rates for the audit period in accordance with the financial procedural aspects of Chapter 4901:1-14, O.A.C., and related appendices and properly applied the GCR rates to

customer bills.

The financial auditor explained that auditor-identified errors between October 30, 2001, and February 28, 2002, as well as several other errors found by the company during the financial audit period were corrected by the company. However, D&T found two overstatements of supply costs (in the amount of \$45,858 and \$474,775) were inappropriate. Also, D&T noted that the company understated its recoveries from ratepayers by a net \$3 for the filings effective October 31, 2001, and May 2, 2002, and such should be corrected. D&T concluded that Vectren's level of unaccounted-for gas, as of October 30, 2002, is below the five-percent ceiling imposed by Rule 4901:1-14-08(F)(3), O.A.C.

None of the parties to this proceeding challenged the findings of the financial audit in this proceeding. Vectren expressly agreed with D&T's findings and noted its actions in making several corrections (Vectren Ex. 2, at 3-5). Moreover, the Commission notes that the financial auditor in Vectren's subsequent financial audit [FN8] reviewed Vectren's post-2002 audit GCR rates and verified that the three adjustments recommended in this proceeding were appropriately made. The parties in 03-220 stipulated that those three adjustments were properly handled and we accepted that stipulation on June 30, 2004. Thus, the Commission considers the financial audit concerns that were raised in this proceeding to be fully resolved.

V. SUMMARY OF UNCONTESTED M/P AUDIT RECOMMENDATIONS AND THE COMMISSION CONCLUSIONS THEREON

Pursuant to the entry issued September 18, 2002, as amended by entry issued November 7, 2002, and Rule 4901:1-14-07(A) and (D), O.A.C., a m/p audit of Vectren was conducted. Liberty's audit team consisted of a project manager and two independent contract consultants (Tr. I, 39-41, 48). Each of the m/p audit team members offered testimony in support of the m/p audit report. As part of the m/p audit, Liberty reviewed Vectren's organizational structure, gas supply management and planning, gas transportation, operational policies and procedures, and the impact on Vectren's ratepayers. The m/p auditor also reviewed selected aspects of Vectren's procurement strategies, gas production and purchasing policies in order to: (1) ascertain whether the company's purchasing policies meet the objectives of the company's service requirements; (2) ascertain whether Vectren's purchase plan is sufficient to ensure reliable service at optimal prices; and (3) evaluate consistency with the company's long-term strategic supply plan and the company's existing and potential supply sources. Liberty made 23 recommendations in its m/p audit report (Comm.-Ord. Ex. 2).

*8 Vectren has agreed to comply with the following m/p auditor's directives:

(1) Develop a decision matrix or chart of authorities that defines the responsibilities and authorities of various levels of management within the gas supply organization by December 31, 2003 (Comm.-Ord. Ex. 2 at I-13; Vectren Ex. 1, at 19).

(2) Develop formalized procedures covering the management of price risks to which Vectren is exposed in the fuel supply area by December 31, 2003 (Comm.-Ord. Ex. 2 at I-13; Vectren Ex. 1, at 19).

(3) Develop a plan for an internal audit of gas supply to be conducted no later than October 31, 2004 (Comm.-Ord. Ex. 2 at I-14; Vectren Ex. 1, at 19).

(4) Replace the recently retired Director of Gas Supply with a seasoned and senior natural gas manager capable of immediately assuming direct responsibilities for management of all natural gas supply operations (Comm.-Ord. Ex. 2 at I-14). In regards to this recommendation, Vectren notes that, on August 18, 2003, Perry Pergola was hired as the new Director of Gas Supply (Vectren Ex. 1, at 20; Tr. I, 20).

(5) Examine the options for reconfiguring Vectren's pipeline capacity and storage portfolios (Comm.-Ord. Ex. 2 at II-15; Vectren Ex. 1, at 20).

(6) Examine the physical constraints on Vectren's system that limit the volumes it may take from individual pipelines before the winter of 2004-2005 (Comm.-Ord. Ex. 2 at II-15). Vectren agrees to examine its options for reconfiguration and physical constraints by April 1, 2004 (Vectren Ex. 1, at 20; Tr. I, 20).

(7) Approach Vectren's large customers with an offer(s) of interruptible service and dual-fuel peaking service option and have such contracts in place by November 1, 2003 (Comm.-Ord. Ex. 2 at II-16). Vectren agrees to accomplish this recommendation by November 1, 2004 (Vectren Ex. 1, at 21; Tr. I, 21).

(8) Develop and file with the Commission, in consultation with Commission staff and approved suppliers, a revised curtailment plan before the winter of 2004-2005 (Comm.-Ord. Ex. 2 at II-17). Vectren agrees to develop and file a revised

curtailment plan in consultation with the Commission staff by June 30, 2004 (Vectren Ex. 1, at 21; Tr. I, 21).

(9) Develop the necessary policies, procedures and internal tools to optimize its gas supply planning activities by no later than April 1, 2004 (Comm.-Ord. Ex. 2 at III-23; Vectren Ex. 1, at 21).

(10) Conduct employee training in affiliate relations by March 31, 2004, and require employees to annually verify, in writing, that they understand the affiliate relations guidelines and intend to comply with the guidelines (Comm.- Ord. Ex. 2 at I-8, I-10, I-14; Vectren Ex. 1, at 20).

(11) Refund \$440,266 (plus interest) to ratepayers for their share of the 'profit' realized when Columbia Gas Transmission Company Inc. (TCO) sold off excess base storage gas in the mid-1990s; and refund \$800,135 (plus interest) for over-injection penalties incurred in October and November 2001 and passed onto GCR customers (Comm.-Ord. Ex. 2 at VI-1-VI-3; Vectren Ex. 1, at 18-19; Tr. I, 18-19).

***9** We are comfortable with the above recommendations and Vectren's agreements to comply with the above recommendations (including the altered time frames). With regard to item 10 above (involving affiliate relations), the Commission finds it appropriate to direct Vectren to develop specific employee policies and procedures governing employee interaction with affiliates (to the extent this is not a part of the training and annual statement to be signed). We make this clarification so that the employee training is not just a 'rehashing' of the existing affiliate relation provisions in Vectren's tariff but, rather, a more meaningful identification of the policies and procedures that affected employees are expected to follow in day-to-day interaction with affiliated entities.

VI. CONTESTED M/P AUDIT RECOMMENDATIONS, THE PARTIES' POSITIONS, AND THE COMMISSION CONCLUSIONS THEREON

In addition to the recommendations noted above to which Vectren has agreed, Liberty makes several other specific recommendation regarding Vectren's gas supply management and gas supply planning. Vectren does not agree with those recommendations. OCC and staff also take positions on most of those recommendations. Each of the m/p auditor's recommendations contested by Vectren is discussed in detail below, including the parties' position on the issue, relevant testimony offered and the Commission's decision.

A. The ProLiance Asset Management Services Contract

Upon acquiring DP&L's gas assets in 2000, Vectren had in place an agreement with ProLiance dated October 31, 2000 (Comm.-Ord. Ex. 2 at II-7; Vectren Ex. 1, at 5; OCC Ex. 1 at Attach. EWL-1). ProLiance is a joint venture between Citizen's Gas & Coke Utility (an Indiana LDC) and Vectren Corporation, Vectren's parent (Comm.-Ord. Ex. 2 at II-7). The agreement provides that ProLiance will solely supply all gas for Vectren's requirements and Vectren will assign all pipeline contracts to ProLiance. The agreement has a five-year term, with a year-to-year rollover provision. Termination of the agreement requires 24 months advance notice (Id.). Other terms of the contract include Vectren's right to recall **capacity** for assignment to gas choice **customers** and Vectren's ability to periodically require certain reductions in the amount of **capacity** demanded. Additionally, the agreement requires VEDO to pay annual **fees** for the **management** services (the first being \$450,000, with the **fee** increasing at the **consumer** price index, less one percent). If pipeline **capacity** is not used in providing service to VEDO **customers**, ProLiance can remarket it, but must pay VEDO a transportation credit, which Vectren flows through to GCR **customers**. In the first year, that credit was approximately \$1.4 million (Id.; Tr. III, 148, 150, 208).

Liberty states that, for many **LDCs**, it makes sense to use an **asset manager** to maximize the value of unused or underutilized **assets** (Comm.-Ord. Ex. 2 at Attach. A2). However, the m/p auditor concluded that the relationship between Vectren and ProLiance is not an arm's length relationship and the agreement is not structured in a way that benefits Ohio **ratepayers** (Id. at II-13). Liberty contends that there are a number of factors which resulted in benefits to ProLiance at the expense of Vectren's **ratepayers** during the audit period, including Vectren's inability to effectively monitor and **manage** the portfolio administration agreement with ProLiance, the inappropriate flow of funds from TCO to ProLiance, and the unfavorable financial **arrangements** (namely, the **management fee** paid by Vectren and the low value of the unutilized **capacity**). Liberty characterizes the contract's **management fee** as highly unusual and inappropriate, but acknowledges that the **management fee** Vectren pays to ProLiance is included in base rates and, therefore, beyond the scope of this proceeding (Comm.-Ord. Ex. 2 at II-13, VI-3). Thus, Liberty's recommendation (discussed further below) for reapportioning the benefits does not include the **management fee**. Still, Liberty believes ProLiance's payment to Vectren for the right to unutilized **capacity** is too low and, thus, **ratepayers** are entitled to a greater **share** of that revenue (Id. at VI-1). Liberty relied upon the DP&L **asset management** contract with Columbia Energy Services (CES) [FN9] as an appropriate market benchmark for valuing the right to the unutilized pipeline **capacity**. [FN10] With that market value, Liberty endorses an 85/15 percent **sharing** of revenues between **ratepayers** and shareholders to provide **ratepayers** with a

reasonable **share** and to encourage **LDCs** to aggressively market their unused **assets** (Id. at VI-3). After taking into account the \$1.4 million payment Vectren already received from ProLiance and its recommended 85/15 percent **sharing** ratio, Liberty determined that \$3.83 million should be refunded to Ohio **ratepayers** as the remaining reasonable **share** of the **asset management** activity under the Vectren/ProLiance agreement during the two-year audit period (Id. at VI-3, VI-5). The m/p auditor acknowledged that another source of information to determine the market value of unutilized **capacity** is the electronic bulletin boards under the oversight of the Federal Energy Regulatory Commission (Tr. I, 182-186; Tr. II, 67).

*10 Liberty also recommends that Vectren issue a request for proposal for competitive bids for **asset management** or portfolio administration services (Id. at ES-5, II-6-II-7). Liberty recommends that the **managed assets** include commodity, pipeline **capacity**, storage and propane facilities (Id. at II-17). [FN11]

OCC concludes that the Vectren/ProLiance agreement was not an arm's length transaction and has caused imprudent and unreasonable costs for GCR **customers**. Like the m/p auditor, OCC reasons that an unbid, affiliate contract, by its very nature, is unreasonable and there is no evidence that the terms and conditions of the contract reflect the prevailing competitive market (OCC Ex. 1, at 9). OCC is not convinced that Vectren maintained appropriate oversight of the relationship because of errors that occurred during the m/p audit period (OCC Br. 2-3, 6-10, 46-50). OCC argues that Vectren failed to ensure that the transportation credits and the amount ProLiance pays to Vectren for unused **capacity** were appropriately credited to **ratepayers** (OCC Ex. 1, at 5, 9; Tr. II, 117). OCC recommends that Vectren pursue a full requirements contract for all of its **asset management** services by competitive bid process (Id.). OCC notes that the request for proposal can seek bids for contracts with and without a provision allotting for gas choice migration, i.e., a right to recall **capacity** (Tr. II, 146). Further, OCC contends that, if no acceptable bid is received, the Commission should require Vectren to renegotiate and restructure the Vectren/ProLiance agreement to incorporate, among other things, a margin-**sharing** mechanism and detailed accounting requirements, and declare the function to be a monopoly function that Vectren should provide at cost (OCC Ex. 1, at 6, 9, 10-11; OCC Br. 11). In addition, OCC advises that Vectren implement an on-going internal audit program, the **asset manager** maintain separate account records for each Vectren gas supply or **capacity** resource transaction and Vectren's monthly gas supply report be enhanced to improve oversight of the **asset manager's** and Vectren's procurement performance (OCC Ex. 1, at 6, 13-14).

Next, OCC recommends that an additional \$745,000 (in addition to the m/p auditor's recommended \$3.83 million) be refunded to Vectren **ratepayers** for the ProLiance **management fee** and **capacity** margins (OCC Ex. 1, at 6, Sch. 1). OCC's witness

contends that each year's \$450,000 **management fee** should be factored into the evaluation of the Vectren/ProLiance agreement. Since the DP&L/CES agreement did not have a **management fee** and it was considered a reasonable market benchmark, OCC reasons that the Vectren/ProLiance \$450,000 yearly **management fee** should be recognized in what OCC concluded is ProLiance's **share** of the margin (OCC Ex. 1, at 6, 15). [FN12] OCC further argues that the transportation credits given were too low because they did not include the second winter delivery service (WDS) contract, which is discussed in detail later in this decision (OCC Br. at 14-15). [FN13] OCC calculates the value of the WDS-2 transportation credit at \$381,373.80 (OCC Br. at 15, Attach. 2). However, the OCC witness admits that he did not review the compensation calculation set forth in the Vectren/ProLiance agreement or independently review the value of the unutilized capacity of the DP&L/CES contract (Tr. II, 112-115, 117). Furthermore, the OCC witness confirmed that the ability to recall capacity for assignment to customer choice suppliers (as is contained in the Vectren/ProLiance agreement) reduces the value of the portfolio administration contract to the portfolio administrator while enhancing the gas choice program (Id. at 122, 128-130). Likewise, requiring the portfolio administrator to pay an upfront fee to the LDC reduces the value of the contract for the potential portfolio administrator (Id. at 125-126).

***11** Staff, like Liberty and OCC, argues that Vectren should have issued the portfolio administration contract for competitive bid (Staff Br. 13). Staff contends that management fees for portfolio administration contracts are highly unusual and that the transportation credits paid by ProLiance to Vectren for excess capacity are low in comparison to the DP&L/CES contract. Staff argues that, since 50 percent or more of Vectren's gas supply contracts expire in 2004 and 2005, Vectren could achieve the capacity reduction it felt was needed for its gas choice program through the expiring contracts rather than with the Vectren/ProLiance agreement (Staff Br. at 14-15). Also, staff believes that Vectren did not hold ProLiance to the terms of the contract (specifically, the mandatory language obligating ProLiance to supply the peak day gas supply amounts, including the five percent reserve margin) (Id. at 15; Staff Reply Br. at 16-18). If Vectren had done so, staff argues that there would have been no need for Vectren to obtain the WDS contracts because ProLiance was contractually obligated to get that supply. Next, staff contends that, since Vectren admittedly never intended to do anything other than contract with ProLiance, Vectren's reliance now upon other asset managers and subsequent events cannot demonstrate the reasonableness of Vectren's contract with ProLiance (Staff Reply Br. at 15). Staff also argues that these factors, among other facts in regards to the Vectren/ProLiance agreement, demonstrate that the agreement was not arm's length or reasonable. Staff believes that Liberty used a reasonable approach to place a market value on Vectren's gas supply assets, but also believes that quantifications are difficult. Staff encourages the Commission to determine an appropriate amount for refund to GCR customers, as well as any other necessary action (Staff Br. at 16).

Vectren disagrees with the contention that the Vectren/ProLiance agreement is unfairly biased toward ProLiance. Vectren mainly chose ProLiance for the following reasons: choice program support, reliability, price and financial stability (Vectren Ex. 1, at 16; Tr. III, 98). Vectren also noted that its board of directors position with ProLiance (Vectren has one of the two members) and its affiliation with ProLiance figured greatly into Vectren's selection of ProLiance as portfolio administrator (Vectren Ex. 1, at 8; Tr. III, 95-96, 104- 106). Vectren also points out that a number of other asset management service providers have had difficulties, even at the time the Vectren/ProLiance agreement was executed (Vectren Ex. 1, at 9; Tr. I, 150). [FN14] Thus, Vectren argues that it was reasonable for it to have selected ProLiance.

Next, Vectren contends that the terms of the Vectren/ProLiance agreement are reasonable and beneficial. Vectren points out that, under the agreement, it has received over \$3 million for unutilized capacity and \$1.4 million for capacity cost reduction, and the agreement has given Vectren great flexibility in assigning capacity to gas choice suppliers if they desire (Vectren Ex. 1, at 16). Vectren notes that, because it was planning to roll out a gas choice program, the contract included capacity reduction right terms [FN15] that allowed Vectren to avoid a mandatory capacity assignment to choice suppliers, while still protecting GCR customers from stranded costs (Vectren Ex. 1, at 8; Vectren Ex. 6, at 17-18, 20-21). Vectren also explained that it and ProLiance jointly conducted a market analysis of capacity release prices, as one of the factors to determine the unutilized capacity contract compensation mechanism, and noted that the highest market value was the value selected (Vectren Ex. 1, at 15 and Attach. JLU-5; Tr. III, 92-93, 110).

***12** According to Vectren, use of the DP&L/CES asset management agreement as a benchmark to evaluate the Vectren/ProLiance agreement is inappropriate for several reasons (Vectren Ex. 1, at 11-14; Vectren Ex. 3, at 8). First and foremost, Vectren characterizes the purpose of the DP&L/CES agreement as one intended to maximize revenue, while its agreement with ProLiance has other goals, such as supporting a gas choice program, mitigating choice-related stranded capacity costs, and obtaining reasonable value for its capacity (Vectren Br. at 30). Vectren believes that the auditor used an incorrect and inflated dollar amount for the capacity purchased by CES, ignored the value associated with the capacity reduction rights held by Vectren, and ignored the devaluation of a significant portion of the DP&L capacity portfolio (the DP&L unutilized pipeline capacity on the TCO pipeline) just prior to Vectren taking over the DP&L assets. Further, Vectren places greater value on its year-round contractual right to 'pull back' capacity when needed for choice customers and the fact that its agreement does not require it to pay refunds to ProLiance when Vectren reduces capacity (Vectren Ex. 1, at 13; Vectren Ex. 3, at 4-8, Attach. PMP-2). Vectren next contends that the contract's compensation mechanism for the unutilized capacity places a significant risk upon ProLiance. [FN16] Specifically, ProLiance gets Vectren's unutilized capacity entitlements based

on the outstanding amount of capacity expected for a normal season and, thus, if the winter is colder than normal, ProLiance pays the same amount but actually has less unutilized capacity to remarket (Vectren Ex. 1, at 14; Tr. III, 151-152). In addition, Vectren notes that Liberty's reliance upon the DP&L/CES agreement is suspect in light of CES' exit from the business and DP&L's and Enron's legal disputes (Tr. I, 173-178; Tr. II, 84-87). Vectren also argues that Liberty's proposed disallowance is greater than the amount CES could have paid DP&L over a two-year period (because, unlike the Vectren/ProLiance agreement, the DP&L/CES agreement required DP&L to compensate CES if the capacity CES purchases was unavailable for some reason) (Vectren Br. at 27, Fn. 28). If the Commission agrees with sharing the revenues, Vectren argues that its share should be at least 30 percent and any adjustment should be reduced by \$1.4 million to recognize the capacity reduction right revenues received during the m/p audit period (Vectren Ex. 6, at 22, 30).

Vectren is aware that ProLiance resells the unutilized capacity received from Vectren, but is unaware if ProLiance repackages the capacity with commodity, how ProLiance bundles the unutilized capacity purchased from Vectren with unutilized capacity from other affiliates, and how successful ProLiance is at selling the capacity (Tr. III, 151-153). Vectren does not track or attempt to determine the compensation ProLiance receives for the unutilized capacity purchased from Vectren or Vectren and its Indiana affiliates (Tr. III, 108- 109).

***13** Finally, Vectren argues strongly against a competitive bid for the asset management contract. Vectren states that it is not a good idea, given current market conditions (few options are out there and the costs/efforts may not produce better results). Vectren doubts any current providers would pass creditworthiness concerns or be willing to agree to Vectren's various 'strings' just for the opportunity to remarket unutilized capacity (Tr. III, 161). Moreover, Vectren believes that conducting a competitive bid will be complicated, particularly because it has a successful gas choice program (Vectren Ex. 6, at 24-25). Vectren does not want to forego the benefits/protections it has in the current asset management agreement. If this is required by the Commission, Vectren states that it must have specific direction on such issues as creditworthiness, control over capacity, and reliability (Id. at 27).

Commission Conclusion

Vectren contends that the Vectren/ProLiance agreement was thoroughly considered and known to OCC and the Commission as a part of 00-220. The Vectren/ProLiance agreement was executed on October 31, 2000, to coincide with the transfer of the gas assets from DP&L to Vectren. The m/p auditor in 00-220, Exeter, took issue with the

Vectren/ProLiance agreement in its report filed May 4, 2001, as supplemented on June 22, 2001. Thus, Vectren is correct that the Vectren/ProLiance agreement was known to OCC and the Commission as a result of the 00-220 proceeding. However, as Vectren clearly understands, 'known to the Commission' and 'approved by the Commission' are two entirely different concepts. In the 00-220 Order issued September 25, 2001 (at 8-9, 11, 12), the Commission recognized that, although Exeter's recommendations in regards to Vectren were beyond the scope of that audit, the m/p audit report raised certain issues and directed the next m/p auditor to review the level of compensation Vectren received for its capacity, among other issues. Plus, Vectren stipulated that the compensation it received for its capacity would be examined in this m/p audit period. Moreover, Vectren acknowledged that, under the gas choice program stipulation in Case No. 02-1566-GA-ATA, In the Matter of the Application of Vectren Energy Delivery of Ohio, Inc. and Other Stakeholders for Approval of a Stipulation That Would Establish a Gas Choice Program (02-1566 or the gas choice program), staff and OCC reserved all rights with respect to the ProLiance/Vectren agreement in this GCR audit and consideration of the value of contract demand reduction rights with respect to the compensation received for unutilized capacity (Tr. III, 146-147). Thus, Vectren was clearly on notice that the Vectren/ProLiance agreement and its compensation terms would be at issue in this proceeding. Nothing in the stipulations or the Commission's decisions in 00-220 or 02-1566 precludes an evaluation of the Vectren/ProLiance agreement.

There is no doubt that the Vectren/ProLiance agreement was not an arm's length deal. That fact, however, does not render the agreement unreasonable. We will not declare the Vectren/ProLiance agreement an imprudent, unreasonable or inappropriate action on Vectren's part simply because it was not the result of a competitive bid. Rather, we will presume that the agreement was a prudent action, but that presumption can be rebutted.

***14** Vectren testified that the company had no intention of awarding the asset management services agreement to an unaffiliated, third party (Tr. III, 104). Thus, the agreement was executed without consideration even being given to any other asset managers. Further, Vectren failed to indicate that it considered the revenues generated for the unused capacity between 1998 and 2000 for virtually the same assets. Rather, Vectren's testimony indicates that it and ProLiance conducted a market analysis of capacity release prices and selected the highest market value (Vectren Ex. 1, at 15 and Attach. JLU-5; Tr. III, 92-93, 110). However, the higher market value contained in the DP&L/CES agreement was not part of that analysis, even though the DP&L/CES agreement involved virtually the same assets.

Liberty suggests that the Vectren/ProLiance contract is not reasonable compared to the DP&L/CES agreement. Likewise, OCC and staff have attempted to rebut the reasonableness presumption by arguing that, in comparison with the DP&L/CES

agreement, the Vectren/ProLiance contract provides unreasonable results. [FN17] The Commission realizes that the asset management agreement selected by the m/p auditor to evaluate the Vectren/ProLiance agreement is not identical in time, terms and conditions to the Vectren/ProLiance agreement. We believe that comparing the two asset management services agreements is logical because they involved the same assets and are relatively contemporaneous with one another. However, there are differences between the two contracts that can arguably justify the different compensation levels for the unutilized capacity. Staff and OCC point to the much lower revenues generated by the ProLiance agreement to support their contention that the ProLiance agreement was not prudent, reasonable or appropriate. The facts illustrate that ProLiance was given what was formerly DP&L's entire pipeline **asset** portfolio for just under \$1 million per year (\$1.4 million in payments from ProLiance minus the \$450,000 yearly **asset management fee** paid by Vectren). This equates to approximately one-fourth of the revenue that DP&L received just one year earlier (\$3.9 million) for use of virtually the same **assets**. Vectren largely justifies the revenue difference on the intervening devaluation of part of the **capacity** portfolio. While there may have been some reduction in the value of that part of the **capacity** portfolio, it is still evident to us that revenues generated from unutilized **capacity** are maximized when **capacity** and commodity are combined as ProLiance has the ability to do. In our opinion, Vectren did not adequately recognize these transactions when negotiating the **asset management** agreement with ProLiance.

Vectren also justifies the lower ProLiance contract revenues on the fact that the agreement included **capacity** reduction rights. Liberty, Staff and OCC argue that the **capacity** reduction right contained in the ProLiance agreement was of little or no value because those reductions occurred at virtually the same time and roughly in the same amount as the expiration of existing pipeline **capacity** contracts. Thus, Vectren could achieve the same results as the **capacity** reduction right by simply allowing its existing **capacity** entitlements to expire. We agree with their assessment as well. Therefore, we do not believe that contract term sufficiently explains the lower ProLiance contract revenues.

*15 Remaining differences between the two contracts (e.g., right to pull back **capacity** and the fact that the ProLiance contract does not require refunds when Vectren reduces **capacity**) do not convince us that the ProLiance agreement is, overall, prudent, reasonable or appropriate. As a result, we believe that Vectren's GCR **customers** have been harmed as a result of this **asset management** agreement.

Next, we believe that Liberty's reliance upon the value of the DP&L/CES agreement was appropriate. As noted, the DP&L/CES agreement was competitively bid, involves virtually the same **assets**, and was in effect in the year prior to the execution of

the ProLiance agreement. Thus, it is a reasonable counterpart to use for determining what a prudent, reasonable and appropriate **asset** service **management** agreement would have provided to Vectren and its **customers** during the m/p audit period. We are willing to accept Liberty's calculation of an appropriate value for the unutilized pipeline **capacity** and its use of an 85/15 percent **share** of revenues between **ratepayers** and shareholders. We accept Liberty's \$3.83 million refund recommendation. We do not, however, accept OCC's suggestion to also include \$745,000 in the refund equation (in order to reflect the yearly \$450,000 **management fee**, less \$155,000 in other payments made to Vectren). The **management fee** was not included in the GCR rates under evaluation in this proceeding and, for that reason, we do not consider it appropriate to include that **fee**.

Furthermore, we agree with Liberty, OCC and staff that a competitive bid is important and should be accomplished forthwith. We reach this conclusion primarily for two reasons. First, we believe Vectren should explore various terms and conditions for its asset management (and not just those willing to be provided by its own affiliate). The time has come for Vectren to reassess its needs and the terms under which that can be properly managed. Second, we believe that the evidence in this case illustrates that Vectren relied too easily upon ProLiance's expertise and could have better monitored its asset manager. With a competitively bid asset manager, Vectren should have a more vested interest in overseeing that manager's activities. Of course, the fact that future GCR audits will take place may also provide that incentive too.

We do not agree with Vectren that issuing a request for proposals from qualified asset managers is not worth the effort. As OCC suggests, Vectren can seek proposals with and without various important terms (e.g., a right to recall capacity). Under such an approach, Vectren can evaluate the importance and value of such terms. Vectren should include commodity, pipeline capacity, and storage. We are not convinced that Vectren must relinquish control over its propane assets to a third-party asset manager. We do believe better use and more aggressive handling of those propane assets is needed (and that is further discussed in the upcoming part of our decision). Even so, we are not convinced that the asset manager must also have control over all of Vectren's propane assets to better maximize the value of Vectren's assets overall. It may be worthwhile, however, for Vectren to include the propane assets (or a portion thereof) as an optional aspect of the request for proposals.

***16** The Commission believes that Vectren should be more active to ensure that its duties and obligations to its GCR customers are being met when the asset management services agreement is held by a third party (affiliated or unaffiliated). Further, as a business entity, the Commission expects Vectren to undertake such activities to evaluate whether Vectren has received the benefit of its bargain and to begin

negotiations for subsequent asset management agreements. To that end, we agree with the following OCC recommendations: (1) Vectren should implement an internal audit program; (2) the asset manager should maintain separate records of each Vectren transaction; and (3) Vectren should improve its oversight of the asset manager and performance. Finally, we realize that Vectren strongly opposed a competitive bid for the asset management services contract. We disagree with that position. However, in the alternative, Vectren can bring the asset management function in-house completely and avoid the competitive bid directive.

B. Propane Storage Assets and Facilities

As a part of its system, Vectren purchased and maintains three propane vaporization plants and an underground propane storage cavern (Todhunter), with a total capacity of approximately 7.5 million gallons of propane (Comm.-Ord. Ex. 2 at II-5, III-15). [FN18] The Todhunter cavern usually contained approximately 3.5 million gallons of propane to commence the winter heating season (Tr. III, 41, 43). Despite DP&L's agreement with Vectren not to make any material change in the level of storage customarily maintained by DP&L, DP&L sold 1,503,000 gallons of the propane out of inventory in September 2000 (Tr. III, 47). In response to the situation presented, Vectren elected not to delay the DP&L asset purchase transaction; Vectren elected, for the sake of its business relationship with DP&L, to forego a legal dispute over the propane inventory (Vectren Ex. 6, at 10-12, 15; Tr. III, 61-67, 230-231). The asset transfer transaction between DP&L and Vectren was effective November 1, 2000 (the first day of the 2000-2001 winter heating season), at which time Vectren purchased and received 2,060,000 gallons of propane in storage (Comm.-Ord. Ex. 2 at III-15).

During the m/p audit period, Vectren entered into three WDS contracts. Vectren executed the first and third WDS contracts in order to meet design day requirements plus a five percent reserve margin during the peak period (Comm.-Ord. Ex. 2 at III-12; Tr. III, 25, 168; Vectren Ex. 6, at 13-14). Vectren entered into the second WDS contract to replace the propane sold by DP&L prior to the asset purchase transaction and because of the winter weather conditions (Tr. I, 103-104; Tr. II, 149; Vectren Ex. 6, at 14; Tr. III, 61). Vectren flowed the demand and commodity costs of the three WDS contracts through to GCR customers (Tr. III, 56). The details of these three contracts are as follows (Comm.-Ord. Ex. 2 at III-12, III-15, III-26, III-27):

Contract	Volume	Effective Date	Period Covered	Gas Obtained/Used
WDS-1	33,500	12/1/00	12/00-2/01	0

	Dth19/day			
WDS-2	52,000	12/21/00	12/21/00-2-	90,000 Dth
	Dth/day		/01	
WDS-3	34,526	11/1/01	11/01-3/02	0
	Dth/day			

.Pp
19'Dth' means decatherm,
which is a unit of
measure for quantities
of gas.

***17** The costs incurred and transportation credits received from these three contracts are as follows (Id. at III-26, III-27; OCC Ex. 1 at Sch. 5; Tr. III, 213-214):

Contract	Demand Costs	Commodity Costs	Total Costs	Trans. Credit Rec'd
WDS-1	\$1,293,- 974	\$0	\$1,293- ,974	\$219,79- 3.5020
WDS-2	\$1,575,- 792	\$935,337	\$2,511- ,129	\$0
WDS-3	\$1,093,- 991	\$0	\$1,093- ,991	\$302,03- 3.4521

.Pp
20There seems to be some ambiguity
with regard to the transportation
credit
associated with the WDS-1 contract.
Vectren stated during the hearing
that the
credit associated with that contract
was not given during the audit
period.
However, during the course of this
proceeding, that error was noticed
and
Vectren acknowledges that the credit
is due to it (Tr. III, 212-213).
Vectren
also stated that the credit 'was
included in subsequent years of
calculations'
(Id.). Vectren states, in its brief,
that Vectren is agreeing to an
adjustment for the transportation

credit for the WDS-1 contract
(Vectren Br. at
49, 52). We believe, from the
statement during the hearing, that
Vectren has
received the WDS-1 transportation
credit. Perhaps Vectren received
the
transportation credit from ProLiance
for that contract after the M/P
audit
period and, at the time of the
briefs, had yet to flow it through
to GCR
customers. Given our conclusion later
in this decision about the
propriety of
executing the WDS-1 contract, we will
not require Vectren to flow the
WDS-1
transportation credit through to GCR
customers.

.Pp
21This is an estimate of the
transportation credit received
based upon the
transportation credit formula
explained by Vectren (contract
volume X number
of days X price per trade
publications) and Vectren's
statement of the price
input (\$0.0729) for that formula
during the audit period (Tr. III,
211,
213-214).

Liberty found that Vectren's propane facilities are more reliable than many other propane facilities around the country because of availability to the storage cavern, a direct propane pipeline to it, the pipeline interconnection with vaporization plants, and their good condition (Comm.-Ord. Ex. 2 at II-11; Tr. II, 14-15). Even so, Vectren did not use a significant amount of propane during the winters of 2000-2001 or 2001-2002 (Comm.-Ord. Ex. 2 at III-15; Tr. II, 10). Moreover, Liberty points out that the company did not project much use of the propane inventory to meet demand requirements (Tr. II, 225-226). Vectren uses propane to meet hourly and peak needs, as a complement to flowing gas (Tr. III, 85-86). This use has been roughly half of the total propane capacity. Vectren has never studied or evaluated

use of the remaining propane capacity (Tr. III, 87-88). Liberty found that Vectren is not adequately utilizing the propane facilities that are readily available to it, particularly when it did not have sufficient other resources available during the audit period to meet the annual needs of the system (Comm.-Ord. Ex. 2 at II-11, III-20). Liberty recommends that the Commission direct Vectren to include the propane storage assets and facilities as part of the competitively bid asset management agreement (Comm.-Ord. Ex. 2 at II-12, II-16). Liberty did not recommend a disallowance based on the costs of the reduced propane inventory.

***18** Liberty agreed that, before increasing the use of propane on the system, Vectren must consider the problems propane may cause with larger customers because of heat content variations and must be careful not to exceed the maximum allowable operating pressure while injecting propane into its system (Tr. I, 205-210; Tr. II, 75-76). Nevertheless, Liberty believes that the propane facilities can further contribute to the company's system needs.

OCC projects that Vectren could use the excess propane supply to provide incremental gas cost credits when wholesale natural gas prices reach a specific level, e.g., \$9.00 per Dth. OCC recommends that the Commission require Vectren to: (1) review the operating and financial feasibility of utilizing its propane storage capacity more fully, including the pursuit of incremental propane sales, (2) analyze the results and (3) report to the Commission (OCC Ex. 1, at 23-24). OCC makes this study recommendation so that Vectren can determine whether such a change in company policy would have a beneficial impact over time (Tr. II, 138-139). OCC further states that such a study could evaluate whether propane might replace some pipeline firm capacity (OCC Br. at 44). OCC contends that it is unreasonable for the company to ignore a potential source of revenue or cost savings (Id. at 46).

Vectren concludes that its propane facilities were designed and intended to be used as peak day supply sources (Vectren Ex. 6, at 27). Vectren argues that there are certain constraints with the use of the propane facilities, including contacting 13 downstream customers, ambient air temperatures, and having sufficient gas flow to mix with propane. Vectren states that the company may use propane to meet hourly demands or to avoid exceeding Vectren's hourly limitations with a pipeline and incurring an hourly pipeline penalty. However, Vectren primarily relies on propane to meet demand on the coldest of days, when the temperature is 18 degrees or colder (Id. at 28; Tr. III, 78-80). Vectren does not believe it should jeopardize the facilities by engaging in other daily activities with these facilities (Vectren Ex. 6, at 28). Yet, Vectren also agreed that, with December 2000 being the second coldest December in the past 54 years, if Vectren had propane in storage, Vectren likely would have used some of the stored propane to meet demand requirements (Tr. III, 40-41). Vectren explains, however, that it is inappropriate to equate the availability of propane with natural gas flowing through interstate pipelines due to

the operational limitations of using propane. Vectren argues that using propane for other trading activities could lead to breakdowns, lead to reduced production capacity, or jeopardize its ability to reliably serve customers (Vectren Br. at 47). For these reasons, Vectren does not believe these recommendations are viable. Finally, Vectren contends that it is not appropriate for the propane facilities to be included in the asset management agreement because that would force the company to turn over control of its propane facilities (Id. at 49).

Commission Conclusion

***19** Vectren did not project much use of its propane nor did it use any significant amount of propane during the winters of 2000-2001 or 2001-2002. Yet, the propane and associated facilities are significant assets available to Vectren. For this reason, as OCC argues, we are convinced that Vectren should conduct a study of the feasibility and benefits/disadvantages of better incorporating the use of the company's propane assets and facilities.

No one is disputing Vectren's laundry list of real-world considerations associated with the use of its propane assets and facilities. All parties acknowledge that there are constraints to take into consideration. However, the m/p auditor and OCC are suggesting that Vectren actually evaluate other uses for its excess propane because financial benefits may exist under certain market conditions. Interestingly, Vectren seems to acknowledge that this is what DP&L did with some of the propane just prior to the asset transfer (Tr. III, 52-53). There is no reason that Vectren cannot evaluate market conditions and consider using its propane for other than peak day or for avoiding pipeline penalties. Roughly, half of its propane supply is not used for peak day supplies or otherwise (Id. at 86-7). There is opportunity available to Vectren and it should be considering it on a regular basis. We do not agree that the acknowledged constraints with propane make it unreasonable or imprudent for Vectren to evaluate other uses for its excess propane. With the volatility of natural gas prices over the past several years, it is even more obvious to us that Vectren should evaluate other uses for its excess propane. The costs and efforts associated with such a study do not outweigh the benefit of having that information and/or the potential monetary benefits to be realized.

The Commission is unwilling to accept Vectren's position on this issue for another reason. As noted earlier in this decision, Vectren wants the Commission to accept its decision to only use the propane assets and facilities for peak day supply or to meet hourly demand (and avoid a pipeline penalty). However, Vectren also wants us to accept that it was reasonable, in the context of the 'extreme' weather of 2000-2001, for Vectren to not use the excess propane supply and to execute the WDS-2 contract. Similarly, Vectren wants us to accept that it was reasonable, in the context of its

design day and reserve margin needs, to not use the excess propane supply and execute the WDS-1 and WDS-3 contracts. Thus, the totality of Vectren's position with regard to its excess propane assets and facilities would be to sanction Vectren's ongoing maintenance and expenses of sizeable and reliable propane assets and facilities for use in very limited circumstances, which Vectren acknowledges has used roughly one-half of the propane supply only. It is illogical for us to agree that ratepayers should cover all propane facility expenses when the facilities are used sparingly and only up to roughly one-half of their capacity, and not require Vectren to evaluate/consider additional uses which can have a positive economic benefit for those same ratepayers. Within six months, Vectren shall conduct the recommended evaluation and file a report with the Commission and provide a copy to OCC. The report shall detail the evaluation conducted and detail the findings and conclusions reached.

C. The Design Day Equation and Inputs

***20** Upon acquiring the DP&L assets, Vectren submitted the 2000 LTFR based upon the DP&L methodology (Vectren Ex. 1, at 9). Exeter, who was auditing DP&L prior to the sale, issued a report related to DP&L, which criticized part of the DP&L model that Vectren had used in its 2000 LTFR. Vectren changed the design day model following the Exeter m/p report by contracting with Regional Economic Research Inc. (Id.; Vectren Ex. 4, at 9-10; Tr. II, 237). The design day forecasts were as follows (Vectren Ex. 4, at 4, Attach. AMM-1):

Year	Design Day Demand Forecast
2000	533,140 Dth
2001	533,934 Dth
2002	532,646 Dth

Liberty utilized Vectren's 2001 and 2002 LTFRs to evaluate Vectren's gas supply planning in this m/p audit period (Tr. II, 168). The m/p auditor analyzed the weather inputs for the design day calculation used in Vectren's 2002 LTFR (Tr. II, 164-168). The m/p auditor did recognize that Vectren changed the forecasting methodology used in the LTFRs as a result of the recommendations made by the prior m/p auditor, Exeter (Tr. II, 169). Even so, the m/p auditor concludes that Vectren overstated its design day requirements during the m/p audit period.

Liberty found that, although Vectren had actual, correct weather data from the National Oceanic and Atmospheric Administration (NOAA), Vectren did not use NOAA temperature and wind data for weather normals and design day assumptions in its 2001 and 2002 LTFRs (Comm.-Ord. Ex. 2 at III-2, III-6-III-7). Liberty notes the Vectren's design day is based on simultaneous extremely cold temperatures and overly high wind

speeds, for which the probability of occurring is once in 54 years or approximately 1.85 percent. Liberty states that, given Vectren's proximity to several pipelines, storage and access to supply basins, and the flexibility of its propane facilities, a more appropriate probability of occurrence is 5 percent, which equates to a lower design day requirement (Comm.-Order Ex. 2 at VI-3). In other words, Liberty found Vectren's design day formula and inputs required 533 MMcf [FN19] of supply during the m/p audit period, whereas Liberty's calculations required five percent less, or 507 MMcf of supply (Id. at III-11, VI-4-VI-5).

Liberty recommends that Vectren make several specific improvements to the design day equation used in forecasting (Comm.-Ord. Ex. 2 at III-9, III-17, III-18, III-22). Specifically, Liberty recommends that Vectren:

(1) Revise its design day calculation to:

(a) Use correct raw weather data from NOAA.

(b) Ensure the proper calculation of such data.

(c) Replace 'dummied' weather winterwind and heat requirement sales with actual variables.

(d) Include an appropriate autoregressive moving average (ARMA) structure.

(2) Use its updated and improved design day information to recalculate the impact on revenue requirements, evaluate the Vectren/ProLiance agreement returns, and report such results to the Commission.

***21** (3) Modify its philosophy underlying the probability of extremely cold weather conditions and high wind speed conditions, and its design day calculations to adjust for a three to five percent probability of occurrence.

Aside from prospectively changing the inputs and equation, Liberty also calculated a rough estimate of the impact upon GCR customers that the excessive design day requirements had during the m/p audit period. Accordingly, Liberty proposes a disallowance of \$2,000,000 for excess capacity costs required by the design day

calculation during the m/p audit period (Comm.-Ord. Ex. 2 at III-17- III-18, VI-4-VI-6). Liberty based its \$2,000,000 amount on a conservative, estimate of the value of selling propane as market conditions allowed during the m/p audit period. The m/p auditor admits the estimate is an imprecise calculation (Id. at VI-3-VI-5).

OCC takes the position that poor planning and handling justify a disallowance in this area. OCC acknowledges that Vectren might have needed a minimal amount of additional capacity during the m/p audit period (OCC Br. at 18-20). However, OCC believes that GCR customers should not be charged with the costs of the three WDS contracts because the evidence shows that Vectren poorly planned and handled the situation. OCC presents several alternative views of Vectren's supply situation. First, we will summarize OCC's arguments about the WDS-1 contract. OCC contends that, when comparing Vectren's stated design day forecast needs in 2000 (533,140 Dth/day) with the total amount of gas ProLiance was contractually required to provide (559,798 Dth/day), the WDS-1 contract and then-existing propane supplies, Vectren ended up having a reserve margin of 21 percent for the winter of 2000-2001 (OCC Br. at 25, 32-35). Thus, under this approach, the WDS-1 contract was not needed for the reserve margin. Alternatively, OCC argues that a straight comparison of Vectren's stated design day forecast needs in 2000 with the amount of winter deliverability identified in the Vectren/ProLiance contract indicates a deficit of either 0 or 4,140 Dth per day (Id. at 19). [FN20] In this situation, the WDS-1 contract, with its 33,500 Dth per day was excessive for reserve margin purposes, in OCC's view. OCC further argues that the WDS-1 contract was not justified by colder than normal weather, as Vectren claims, [FN21] because the decision to enter into the WDS-1 contract was likely based on the weather experienced during only a part of November 2000 and it is not reasonable for Vectren to respond to cold weather during less than one-fifth of the winter heating season (OCC Br. at 27).

Next, we outline OCC's WDS-3 contract arguments. OCC argues that Vectren had a reserve margin of 20.1 percent for the winter heating season of 2001-2002 with the addition of the WDS-3 contract, based upon the figure identified as the total amount of gas ProLiance was contractually required to provide (559,798 Dth/day) (Id. at 25-26). Alternatively, OCC calculates that, if the audit report figure is correctly referencing cubic feet, Vectren might have had a deficit of 9,000 Dth/day for the 2001-2002 winter heating season (OCC Reply Br. 43). In this scenario, OCC considers the WDS-3 contract as excessive too.

***22** Third, we turn to the WDS-2 contract. OCC asserts that the company had a 1.7 percent reserve margin after the first WDS contract (OCC Ex. 1, at 21). Thus, OCC argues that Vectren may not have needed the WDS-2 contract because the WDS-1 contract provided enough additional supply to fulfill Vectren's design day requirement and reserve margin, even taking into account the low propane supply (OCC Br. at 21). Alternatively, assuming the WDS-2 contract was really needed for

replacing the missing propane (as Vectren alleges), OCC views the WDS-2 contract as 'overkill' because it provided 3.12 million Dth when the missing propane was 136,636 Dth (OCC Br. at 22). OCC calculates that the addition of the WDS-1 and WDS-2 contracts resulted in a 15.3 percent reserve margin (Id. at 23). Additionally, OCC questions why the company did not use its propane supply on hand, instead of obtaining the WDS-2 contract (Id. at 24).

OCC takes the position that GCR customers should not be required to pay the cost incurred to replace the propane removed by DP&L (OCC Ex. 1, at 22). OCC contends that Vectren did not hold DP&L to the requirement of the sale agreement to use 'good utility practices' as to the assets and Vectren's failure was imprudent or unreasonable pursuant to Section 4905.302(E), Revised Code (OCC Br. at 35-36, 38-40). Therefore, OCC reasons that Vectren's shareholders, not the GCR customers, should bear the financial consequences of that management decision. OCC argues that, while Vectren management accepted the risk associated with its decision to not delay the asset transfer, Vectren should not be permitted to shift that risk to ratepayers (OCC Br. at 41-43). OCC calculates the cost of replacing the transferred propane to be \$2,132,229, which is the incremental demand costs and commodity charges under the WDS-2 contract (OCC Ex. 1, at 7, 22, Sch. 5). OCC further notes that ratepayers paid for replacing the propane the following spring (at a cost of \$750,000) (OCC Br. at 42). Taking the three WDS contracts and the propane replacement altogether, OCC requests a total adjustment of \$4,520,194 for excess costs.

Staff's position on this issue addresses both the design day methodology and Vectren's handling of forecasted supply. Staff asserts that Vectren's methodology plans for a design day when both extreme temperature and wind speed occur simultaneously, something that has not occurred in Vectren's territory in the past 54 years that NOAA has recorded such information (Staff Br. at 10). Staff argues that Vectren's 2001 LTFR (with the new methodology) produced results very similar to Vectren's 2000 LTFR (with the methodology inherited from DP&L) because the 2001 LTFR included some changed components, but then used more extreme weather variables (Staff Reply Br. at 6-7). Staff contends that, while Vectren claims to have incorporated Exeter's forecasting recommendations in the 2001 LTFR, the company actually used more extreme weather variables than those used in the 2000 LTFR. In other words, staff believes that the last m/p auditor's recommendation to use extreme weather variables that have a reasonable probability of occurrence on the same day was not followed (rather, Vectren did the opposite and reduced the design day probability of occurrence by using even more extreme weather variables). In staff's view, planning for such overly extreme conditions was unreasonable and contracting for two of the WDS contracts in order to meet the reserve margin (over and above the overstated design day) or to meet its design day requirements (when the asset manager agreed to provide those requirements) was not necessary or justified (Staff Br. at 11; Staff Reply Br. at 9-10). Staff also notes that two of the three WDS contracts were not used to provide gas to GCR customers. For those

reasons, staff contends that Vectren was not justified in executing the first and third WDS contracts and their demand costs (roughly \$1.3 and \$1.1 million) should be disallowed (Staff Br. at 10).

***23** With regard to the WDS-2 contract, staff contends, like OCC, that Vectren entered the 2000-2001 winter heating season knowing that it had a significant peaking capacity shortage because it discovered DP&L's propane sale prior to the closing, but Vectren made a decision to nevertheless complete the asset purchase (Staff Br. at 12; Staff Reply Br. at 10). Staff points out that, if DP&L had not sold the 3.5 million gallons of propane, Vectren would have paid for that inventory as well. Moreover, staff highlights that Vectren claims that the WDS-2 contract was entered into in order to replace the depleted propane supply (Tr. III, 61). Staff considers the events to be a shift from shareholders paying for the propane amounts (as part of the asset purchase agreement) to ratepayers paying for the replacement contract (as part of the passed along WDS-2 contract costs), while ProLiance was entitled to use the additional capacity for its own profit without paying a transportation credit to Vectren or the GCR customers (Tr. III, 214). Staff argues that what would have been a \$574,500 cost borne by shareholders ended up being a roughly \$2.51 million cost imposed upon GCR customers (Staff Br. at 12-13; Staff Reply Br. at 11). Staff recommends that the Commission disallow all demand costs associated with the WDS-2 contract (\$1,575,792) and the commodity costs as adjusted to reflect that some commodity costs would have been incurred without the WDS-2 contract (\$556,437) (Staff Reply Br. at 11). [FN22] Further, staff recommends that, if the Commission does disallow the WDS-2 contract costs as staff suggests, there should not be an additional credit to the GCR customers to reflect the transportation credit. However, if the Commission does not disallow the WDS-2 contract costs as staff suggests, there should be an additional credit to the GCR customers (\$381,373.80) to reflect the transportation credit (Staff Reply Br. at 11-12). Lastly, staff advocates that the Commission require a \$574,500 refund to GCR customers and not allow the shareholders to be better off because of the missing propane (Id.). In summary, the staff's recommended disallowance for design day planning and handling (based on the WDS contracts) is as follows:

Preferred recommendation	
WDS-1 Contract	\$1,293,974 demand costs
WDS-2 Contract	\$1,575,792 demand costs
	\$556,437 commodity costs
WDS-3 Contract	\$1,093,991 demand costs
Total	\$4,520,194
Alternative Recommendation (if there is no disallowance for the WDS-2 contract)	
WDS-1 Contract	\$1,293,974 demand costs

WDS-2 Transportation Credit	\$381,373.80
Make-whole for missing propane	\$574,500
WDS-3 Contract	\$1,093,991 demand costs
Total	\$3,343,838.80

Vectren believes that, over the audit period, it appropriately responded to the Exeter recommendations and took the initiative to develop a better design day calculation (Vectren Ex. 4, at 5-6). Next, Vectren believes that, even if it used an inappropriate value for one of the weather criteria, the resulting forecast was still valid when viewed in context with prior forecasts (Id.). Vectren believes its efforts have been ignored and that the auditor has engaged in unfair second guessing (Vectren Ex. 1, at 10). Vectren is willing to further improve its design day model and inputs, but disagrees that a disallowance is warranted. Moreover, Vectren states that a \$2 million or more disallowance is unreasonable given that Liberty has taken its first full review of Vectren's new methodology and Liberty's position appears to disagree with not only Vectren, but also Exeter and DP&L (Id.).

***24** According to Vectren, one difference of opinion between Liberty and Vectren on the design day equation appears to be whether the previous day temperature should be included when developing an overall probability of occurrence (Vectren Ex. 4, at 10). Since Liberty did not adjust the prior day temperature to a five percent probability of occurrence before calculating the results (as Vectren did), Vectren believes that Liberty's final probability of occurrence is higher than five percent (causing lower design day requirements) (Id. at 11). Vectren believes that the previous day temperature should be included in the development of the probability of occurrence, which results in a higher design day requirement (Id.). Also, Vectren explains that it appropriately uses NOAA data by transforming it to gas day applicable (Id. at 17). Vectren contends that Liberty does not recognize the difference between NOAA's calendar day temperatures (12:00 a.m. to 12:00 a.m.) and gas day temperatures (9:00 a.m. to 9:00 a.m.) needed to more appropriately reflect daily gas demand. Further, Vectren argues that its use of a rolling 30-year normal, rather than Liberty's use of a fixed 30-year normal issued by NOAA, is more accurate. Vectren reasons that NOAA's 30-year normal, for example, is based on a 30-year period ending with the current decade. In other words, for the year 1999, NOAA's 30-year normal would be based on 1961-1990. Vectren uses the most recent 30-year period instead (Id. at 17-18). Vectren states that its use of 'dummied' variables in the calculation is a well-accepted, justified practice in design day forecasting that should be allowed to continue and a practice which can improve the accuracy of the forecast results (Id. at 12- 14). Vectren further disagrees with including an ARMA structure to fix the model; Vectren contends that the better approach is to input better variables (Id.).

Vectren also points out that OCC and staff agreed that Vectren's 2000 LTR

substantially complied with the requirements of Chapter 4935, Revised Code, they raised no issues with Vectren's 2001 LTFR, and they accepted Vectren's plans for its gas choice program. Vectren contends that OCC and staff should not attack the Commission's previous decisions in Vectren's 2000 and 2001 LTFR cases and the choice program (Vectren Ex. 6, at 1-2, 4) by claiming that the design day equation and/or calculations are excessive. Vectren believes it is fundamentally unfair for OCC and staff to claim in this proceeding that Vectren's reliance upon the 2000 and 2001 LTFRs (including the design day calculations) for gas supply planning purposes was improper (Id. at 7; Tr. III, 228-229). [FN23]

Turning to the specific WDS contracts, Vectren explains that the first and third WDS contracts were executed to bring the supply it inherited from DP&L up to design day requirements and the required reserve margin. On this basis, Vectren believed it would have the necessary supplies to support the supply plan. To address the propane inventory issue and weather situation encountered in November and December 2000, Vectren executed the WDS-2 contract. Altogether, Vectren argues that the services under contract provided the level of supply reliability that Vectren required and were reasonable and prudent measures (Vectren Br. at 25-26).

*25 Vectren opposes the claim to disallow a portion of its gas costs incurred to replace the propane removed by DP&L. Vectren states that its decision to not delay the asset purchase transaction and to forego speculative litigation with DP&L was reasonable (Vectren Ex. 6, at 11-12). Vectren considers this recommendation a punishment for a situation that Vectren did not create (Id. at 15-16). Also, Vectren states that a disallowance would encourage LDCs to manage their business by exposing customers to greater risks; instead, reasonable discretion should be afforded (Id.). Vectren relies on Consumers' Counsel v. Pub. Util. Comm. 56 Ohio St.2d 319 (1978) at 324-325, to support its decision to forego litigation (Vectren Br. at 11). In that case, OCC opposed the Commission's order approving costs incurred by an electric distribution company for coal below a specified energy level. In the court's decision upholding the Commission's order, the court recognized that it is not an uncommon business situation where business interests transcend possible legal rights and it was not an unreasonable practice for the electric company to look beyond the immediate contract, perhaps to the neglect of dubious legal rights, for the sake of future business concerns. Vectren contends that, in its situation, it was relying on DP&L to perform other service functions for three years after the asset purchase and did not want to impact that relationship with litigation. Vectren contends that it is inappropriate for other parties to recommend litigation as the preferred process by which Vectren could recover any costs incurred to ensure reliable service for its customers during the winter of 2000-2001 in light of the reduced propane inventory. Vectren asserts that its decision to enter into the WDS-2 contract, and, thereby, replace the propane lost and restore peak day capacity, was well-founded.

Vectren further states that, if the Commission agrees with the recommended disallowance for the Vectren/Proliance agreement's unutilized capacity, then the Commission should not preclude Vectren from recovering actual costs incurred for the WDS contracts because that would effectively penalize Vectren twice for the same thing (input a higher value for the unutilized capacity and preclude Vectren from recovering its costs incurred to satisfy its determination of need) (Vectren Ex. 6, at 31).

Commission Conclusion

The first issue to be addressed in this area is Vectren's argument that OCC and staff are unfairly claiming design day errors when they have accepted the assumptions in other cases. We essentially addressed this issue earlier in our decision when we considered Vectren's motion to strike. We rejected Vectren's position that this GCR proceeding could not include issues associated with Vectren's supply purchases based upon its supply forecast. Similarly, we disagree that the m/p auditor cannot express an opinion about the impact that Vectren's forecasts (and particularly the design day equation) had upon its purchasing policies and behavior during the m/p audit period. We believe that the concerns raised by Liberty, OCC and staff are legitimately before us in this proceeding.

***26** Forecasting, by its very nature, is not a precise undertaking. Thus, the arguments made by Liberty and staff about Vectren's design day equation and inputs are intended to bring about design day results that are within a reasonable range of acceptance. Overall, we are not convinced that Vectren has offered to the Commission sufficient justification for refusing to implement further revisions to Vectren's forecasting/gas supply planning processes. In particular, Liberty and Vectren each contend that the other is not appropriately using NOAA weather data. We believe that simultaneously assuming extremely cold temperatures and overly high wind speeds will reasonably occur is too conservative for design day forecasting (particularly when the effect is that the combination will occur only once or not at all in a 54-year period). Nor do we feel that such an assumption is fully consistent with Vectren's argument that rolling NOAA 30-year normals (instead of fixed period normals) and previous day temperatures must be used to include more contemporary weather data and bring about more balanced results. Thus, we believe Vectren should incorporate Liberty's recommendation to modify the probability of extremely cold weather conditions and high wind speed conditions, and adjust for a three to five percent probability of occurrence.

Also, there is conflicting arguments as to whether Vectren truly implemented the improvements recommended by Exeter in its evaluation of the 2000 LTFR. A comparison of the design day forecasts does not assist us in determining this question either.

The results, which do not include a reserve margin, are as follows:

Year	Design Day Demand Forecast
2000	533,140 Dth
2001	533,934 Dth
2002	532,646 Dth

(Vectren Ex. 4, at Attach. AAM-1; Tr. II, 237.) The results do illustrate to us that Vectren's new methodology changed a number of aspects of the design day forecast because, if only Exeter's recommendations had been implemented, the forecast should have resulted in lower demand requirements. The result of the 2001 design day LTFR took the demand numbers in the opposite direction from that recommended by Exeter and that leads us to believe various assumptions became more conservative (resulting in higher design day requirements). Thus, we find that, to some extent, Vectren's methodology is too conservative. The facts bear this conclusion out because, throughout the m/p audit period, Vectren had sufficient resources to meet its design day requirements, but it did not have sufficient resources to meet the annual needs of the system because of various offsetting problems (Comm.-Ord. Ex. 2 at III-20). For these reasons, we find it appropriate to direct Vectren to adopt the recommendations made by Liberty to improve its design day forecast. Vectren should incorporate the ordered improvements to its design day assumptions, calculation and evaluation into the next LTFR to be filed with the Commission. Moreover, Vectren is hereby put on notice that the company may be at risk for future disallowances of costs related to its design day and capacity if the Commission determines that the company has not taken adequate steps to achieve an appropriate design day.

*27 Now, we turn to the various recommended disallowances because of Vectren's planning and handling and the resulting excess capacity. As Vectren points out, the Commission must exercise restrained and limited judicial review in regards to excess capacity determinations. Consumers' Counsel v. Pub. Util. Comm., 67 Ohio St. 2d 153 (1981). The Ohio Supreme Court reasoned in that case that:

It is unrealistic to expect a utility to have only the precise amount of capacity needed at any given time Limited judicial review of an excess capacity determination is sound for the reason that while excess capacity analyses have an aura of precision about them, they are fraught with judgments and assumptions.

Id. at 158.

There is no dispute that excess, unused capacity existed during the m/p audit period. Liberty calculated how the overstated design day calculation caused the excess capacity situation and impacted ratepayers. We agree that further refinement of the equation is warranted and we believe that the results of the design day equation (versus the customer demand) during the m/p audit period justify a disallowance. We do not, however, believe any disallowance for the resulting excess capacity situation should be based upon Liberty's rough calculation of selling propane when market conditions would have allowed during the m/p audit period. This approach/calculation is very arbitrary and fraught with judgments and assumptions.

OCC and staff argue that Vectren's poor planning and handling resulted in excess costs to GCR customers for the three WDS contracts. Vectren claims that the WDS-1 contract was executed for its design day plus reserve margin needs (Comm.-Ord. Ex. 2 at III-12; Tr. III, 25, 168; Vectren Ex. 6, at 13-14). Vectren's 2000 LTFR (filed with the Commission on December 8, 2000) did not include the WDS-1 contract, even though it had already become effective. Thus, there is some question of how needed the WDS-1 contract was when Vectren's LTFR prepared at the same time does not include the contract that Vectren is executing on the basis of immediate need. The record reflects that, at that time, Vectren had available 477,000 Dth of gas per day and a peak shaving supply of 52,000 Dth of gas per day, for a total of 529,000 Dth of gas per day (Tr. III, 73, 193). At that time, Vectren's design day requirements were 533,140 Dth per day (Vectren Ex. 4 at Attach. AMM-1). The difference needed was 4,140 Dth per day. The volume under the WDS-1 contract (33,500 Dth per day) was well beyond the difference between Vectren's then-existing supply and its design day needs. If we were to include a five percent reserve margin on top of Vectren's 2000 design day requirements, Vectren forecasted a need for 559,798 Dth per day and the volume under the WDS-1 contract (33,500 Dth per day) would be understandable. However, as we address in the next section of this decision, we do not accept that a five percent reserve margin was appropriate on top of forecasted design day needs and, thus, find that the WDS-1 contract resulted in imprudent, unreasonable and inappropriate excess capacity costs of \$1,293,974 for which Vectren's GCR customers should not be responsible.

***28** With respect to the WDS-2 contract, Vectren took roughly three percent of the WDS-2 contract supply (90,000 Dth of 3,588,00 Dth contracted) during the contract period. Vectren contends that it executed the WDS-2 contract because of the propane shortfall and the 'extreme' weather conditions experienced during November and December 2000 (Tr. I, 103-104; Tr. II, 149; Vectren Ex. 6, at 14; Tr. III, 61). As noted, 1.5 million gallons of propane were not in storage when Vectren acquired the DP&L assets. That amounts to a 136,636 Dth shortfall (Comm.-Ord. Ex. 2 at III-20). Vectren had just obtained the WDS-1 contract to address in part design day needs and Vectren already had a sizeable amount of propane available to meet its needs. Thus, the WDS-1 contract and the remaining propane could have covered the same concerns that Vectren advances to justify the WDS-2 contract. Moreover, the WDS-2 contract

was nearly 26 times the amount of the missing propane. Vectren provides no explanation to justify a contract that is so much larger than the main reason for its existence. Additionally, Vectren did not explain why it did not use any of its propane on hand or the WDS-1 contract for the 90,000 Dth of gas it obtained under the WDS-2 contract. The handling of the WDS-2 contract doubled the WDS demand costs to GCR customers and resulted in no transportation credit from ProLiance even though the asset management services agreement appears to have required one. In light of all of these facts, we are not convinced that Vectren prudently, reasonably or appropriately executed the WDS-2 contract or obtained gas under it. Therefore, we believe that a disallowance must be ordered for the \$1,575,792 demand costs and \$556,437 adjusted commodity costs of the WDS-2 contract (as recommended by staff).

Next, we will address the reduced propane inventory as of November 1, 2000. The Commission is not inclined to direct a party to pursue litigation as a first means to address a business dispute. We also recognize, as was noted in the case cited by Vectren, that it is not an uncommon situation that business interests transcend possible legal rights. However, while the cost of purchasing DP&L's gas assets was appropriately reduced for Vectren's shareholders, GCR customers fully incurred the costs of the reduced propane inventory. We agree that this was a shift in responsibility. The Commission finds it inappropriate to shift the risk of the business decision from the Vectren shareholders to the GCR customers. Vectren argues that to disallow the costs incurred to replace the propane removed by DP&L amounts to a punishment for a situation that Vectren did not create (Vectren Ex. 6, at 15-16). However, that same point applies to the GCR customers -- why should the GCR customers pay or be punished by DP&L's decision to remove the propane as well as Vectren's decision not to pursue the issue further with DP&L? The Commission agrees with staff and OCC that the cost to replace the missing propane inventory should not be borne by the GCR customers and, therefore, an adjustment is appropriate. We believe that the already-ordered \$556,437 adjustment for WDS-2 commodity costs (which reflects the difference between the cost of commodity purchased under the WDS-2 contract and the cost for the missing amount of propane from the inventory if it had been replaced at or near the time of the transfer) is the appropriate amount by which GCR customers should be compensated for Vectren's imposition of its business decision to not pursue the missing propane issue. As advocated by Staff and OCC, the GCR customers need not have fully incurred the costs to replace the 1,503,000 gallons of propane missing from the transferred inventory. We note that Staff and OCC provided similar mathematical calculations on this topic (Staff Reply Br. 11; OCC Ex. 1, at Attach. 5), although OCC also calculated the adjustment at \$575,649 based upon the book inventory price of propane instead of the then-market price of propane (OCC Reply Br. 34). We have accepted the use of the then-market price of propane.

***29** Lastly, we turn to the WDS-3 contract. Going into the 2001-2002 winter heating season, Vectren had available 477,000 Dth of gas per day and a peak shaving supply

of 52,000 Dth of gas per day, for a total of 529,000 Dth of gas per day (Tr. III, 73, 193). Vectren's design day requirement (without a reserve margin) was 533,934 Dth per day (Vectren Ex. 4 at Attach. AAM-1). The difference needed was 4,934 Dth per day. The volume under the WDS-3 contract (34,526 Dth per day) was well beyond the difference between Vectren's then-existing supply and its design day needs. Moreover, at this time, Vectren knew of the 'overly conservative' criticisms raised with the DP&L design day formula and had taken them into consideration. Yet, the 2001 design day forecast was greater than the 2000 design day forecast. As we address in the next section of this decision, we do not accept that a five percent reserve margin was appropriate on top of 2001 forecasted design day needs and, thus, find that the WDS-3 contract resulted in imprudent, unreasonable and inappropriate excess capacity costs of \$1,093,991 for which Vectren's GCR customers should not be responsible.

D. The Five Percent Reserve Margin

After determining requirements for design day conditions, Vectren adds a five percent reserve margin to develop its supply plan (Comm.-Ord. Ex. 2 at III-18; Tr. III, 33). The reserve margin is maintained in the event of a shortfall in peak day supply resulting from a supplier or facility failure (Vectren Ex. 6, at 8).

Since Vectren's design day equation already includes a margin of error, Liberty believes an additional five percent reserve margin is unnecessary (Comm.-Ord. Ex. 2 at III-18; Tr. I, 211). Liberty also found that, during the m/p audit period, Vectren was fortunate to have had sufficient resources to meet its design day requirement, but it did not have sufficient resources to meet the annual needs of the system (Comm.-Ord. Ex. 2 at III-20). This occurred because of various offsetting problems. Liberty concluded that Vectren solved the annual shortfall problems with the short-term WDS contracts, but should instead address the underlying problem -- its forecasting. Arguably, Liberty contends that Vectren has no incentive to be more accurate because whatever commodity and capacity was not used up during the m/p audit period was available for ProLiance's benefit (Id. at III-20-III-21). Taking into account Liberty's proposed amendments to Vectren's design day assumptions and calculations, and Vectren's minimal use of propane, the m/p auditor recommends that Vectren reassess its use of a five percent reserve margin applied to its design day gas supply calculations (Comm.-Ord. Ex. 2 at III-11, III-18, III-23).

Upon examination, Liberty acknowledged that, as a LDC prepares to introduce a choice program, the LDC must pursue a strategy to minimize stranded cost exposure without thwarting gas choice initiatives. Liberty realizes that a gas utility with provider-of-last-resort responsibilities and with a customer choice program may be required to maintain higher levels of capacity than it would otherwise be required

to hold in order to meet the needs of sales customers (Tr. I, 190-191; Tr. II, 91-92). Further, the m/p auditor agreed that, even where a LDC is relieved of its provider-of-last-resort obligations, it is likely the LDC would continue to hold pipeline storage and other capacity to maintain system integrity (Tr. I, 194-195).

*30 Staff argues that the Commission did not approve Vectren's five percent reserve margin as a part of the 2000 LTFR proceeding, the 2001 LTFR proceeding or the company's gas choice program (Staff Br. at 7-9). Staff argues that it is illogical to assert that the mere passing reference to the idea of a reserve margin in the 2000 LTFR can imply Commission approval of a five percent reserve margin. Staff further notes that a reserve margin was not actually incorporated into the 2000 LTFR and also contends that such 'approval' as Vectren asserts would allow Vectren to implement any level of a reserve margin (Staff Reply Br. at 3). Staff posits that, legally, the Commission could not have approved a reserve margin as a part of Vectren's LTFR. Staff interprets Section 4935.04(F), Revised Code, to require the Commission to make determinations of reasonableness only as to issues concerning forecasts of loads and resources regarding population growth estimates and as to the assumptions in the LTFR (Id. at 3-4). Furthermore, staff states that the gas choice stipulation agreement does not provide for the cost of the reserve margin (as part of the balancing cost rider) to be recovered from customers, as Vectren claims. Staff contends that the balancing cost rider, established in the gas choice stipulation, was never intended to include a reserve margin (Id. at 9). Thus, the staff reasons that it is unreasonable for Vectren to argue that the Commission has already approved a five percent reserve margin. Staff concludes that the five percent reserve margin is unreasonable.

Vectren contends that its forecasting process and the implementation of a five percent reserve margin to meet reliability requirements is reasonable and appropriate (Vectren Ex. 4, at 15-16). Vectren also believes that Liberty is not fundamentally disagreeing with Vectren on this point (Id.). Vectren agrees with Liberty that an error margin is appropriate for the design day calculation, but Vectren contends an appropriate reserve margin is also necessary (Vectren Ex. 4, at 10). Moreover, Vectren notes that many utilities use a reserve margin and the majority of those use a reserve margin of five percent and its gas choice working group also agrees with its five percent reserve margin (Id. at 16, Attach. AMM-10; Vectren Ex. 6, at 7). Vectren asserts that the use of a reserve margin is even more critical where a gas choice program exists because it serves to provide reliability to gas choice customers as well (Vectren Ex. 6, at 7).

Vectren also believes that OCC and staff have reviewed and endorsed the five percent reserve margin in its settled 2000 LTFR proceedings because Vectren pointed out its use of a reserve margin in that filing (Vectren Ex. 6, at 9- 10). Vectren argues that, legally, staff and OCC are foreclosed, in this GCR proceeding, from

challenging Vectren's use of a reserve margin because OCC and staff agreed that the 2000 LTFR substantially complied with the requirements of Chapter 4935, Revised Code. Similarly, Vectren argues that the reserve margin was discussed as part of its gas choice program docket and parties therein agreed upon recouping reserve margin costs (Id. at 7-8). According to Vectren, any concerns over the reserve margin should have been raised in the LTFR case. Furthermore, Vectren notes that both OCC's witness and the m/p auditor acknowledged that, in order to recognize the uncertainty of demand forecast and unforeseen service issues, reserve margins are appropriate as a gas distribution industry practice (Tr. I, 211; Tr. II, 110). Vectren emphasizes that the m/p auditor did not suggest that Vectren's capacity planning or purchases were imprudent. Vectren admits that the 2000 LTFR (Vectren Cross Ex. 5 at Section 4901:5-7-02) did not reflect the percentage of the reserve margin or quantify in volumes the reserve margin gas, but mentioned it in the special topics discussion (Tr. III, 26, 34-36).

Commission Conclusion

***31** The Commission recognizes that Vectren acquired the assets of DP&L and developed its 2000 LTFR, filed on December 8, 2000, using DP&L's methodology. We also acknowledge that Vectren, staff and OCC filed a joint stipulation resolving the issues associated with the 2000 LTFR and the stipulation was approved by the Commission on September 25, 2001. The Commission notes, as a Vectren witness admits, the concept of a reserve margin was only mentioned in a passing fashion and was not numerically reflected in the 2000 LTFR. The 2000 LTFR states merely that: 'Another aspect of reliability is the practice of incorporating a reserve margin into the peak day planning process. This reserve margin provides additional reliability to customers given that the demand forecasting process although detailed in its process is a forecast and will have variances when compared to actual demand' (Vectren Cross Ex. 5, at Section 4901:5-7-02). As was explained in detail in the Section II of this decision, the Commission finds that Vectren misinterprets the purpose of the LTFRs and the scope of the Commission's ruling in such LTFR cases. As for the parties' recommendation and the Commission's conclusions in Vectren's gas choice docket, we do not accept that staff and OCC are foreclosed (collaterally estopped) from supporting the m/p auditor's recommendation in the area of a reserve margin. As we already noted, there is no mention of a reserve margin in the gas choice docket stipulation. Vectren states that the reserve margin was agreed upon as part of the gas choice balancing cost rider (Vectren Ex. 6, at 7). That rider states that Vectren will recover, among other things, the costs associated with reserve capacity held by the company in its status as provider of last resort. While staff and OCC agreed to include a balancing cost rider (stipulation page 9, at section G) as part of the gas choice program start up, they also agreed that the rider and its underlying calculation would be reevaluated. Moreover, there was no expressed agreement to a five percent reserve margin.

The Commission finds that each gas distribution utility must support the use of a reserve margin and the percentage level of its proposed reserve margin. In this case, we concluded that Vectren's design day was too conservative during the m/p audit period and found that the company had used only minimal amounts of propane during the m/p audit period winter heating seasons. We realize that many utilities have reserve margins. Moreover, we note that the auditor itself found that a reserve margin can be reasonable and OCC's witness acknowledged that a range of one to five percent can be reasonable (Tr. I, 211; Tr. II, 110). It was the cumulative effect of Vectren's very conservative design day requirements combined with a five percent reserve margin that caused the m/p auditor's concern in this area. However, we must also recognize that we have, in the past, warned and questioned the use of reserve margins. In 1996, the Commission was skeptical about the use of a reserve margin and directed the future m/p auditor to evaluate the issue. In the Matter of the Regulation of the Purchased Gas Adjustment Clause Contained Within the Rate Schedules of The East Ohio Gas Company and Related Matters, Case No. 95-219-GA-GCR, Opinion and Order at 11 (April 25, 1996). Thereafter, that utility and two m/p auditors concluded that design day requirements and capacity resources were in balance and found no need for a reserve margin. In the Matter of the Regulation of the Purchased Gas Adjustment Clause Contained Within the Rate Schedules of The East Ohio Gas Company and Related Matters, Case Nos. 97- 219-GA-GCR and 02-219-GA-GCR. We also find that Vectren's own argument regarding the devaluation of capacity as a reason for the reduced value of the ProLiance agreement, argues against the need for a reserve margin. If that part of the capacity portfolio had been seriously devalued, then Vectren's capacity was limited in moving gas to the east coast and there would have been excess capacity, which was readily available in Vectren's service area. Vectren's own witness acknowledged that the alleged devaluation would effectively have limited the use of Vectren's capacity to the east coast (Vectren Ex. 3, at 5; Tr., 203-204). If that availability of excess capacity occurred, then excess or unutilized capacity was readily available to meet Vectren's alleged shortfalls during the m/p audit period and Vectren would have had no reason to acquire two additional contracts (WDS-1 and WDS-3) for an additional \$2.4 million. Given this availability, the Commission is not convinced that a reserve margin, yet alone a five percent reserve margin, was justifiably implemented by Vectren. Based on the evidence presented in this case, the Commission concludes that Vectren's implementation of a five percent reserve margin during the audit period was not prudent, reasonable or necessary.

E. Evaluations of Forecasting in the Vectren/ProLiance Morning Meetings

***32** Vectren performs a daily forecast using the Regional Economic Research (RER) forecasting model, which is cross-checked (Comm.-Ord. Ex. 2 at III-21). Additionally, Liberty states that ProLiance often changes the forecast after giving its input, but Vectren does not know if the result ends up being a least-cost plan for Vectren (Id.). Therefore, Liberty proposes that Vectren evaluate whether each

day's supply plan actually meets the least cost supply conditions when compared with the originally proposed supply plan (Id. at III-24).

Vectren contends that Vectren's daily least cost supply plan is not impacted by ProLiance's modifications at the morning planning meeting. Vectren explains that, pursuant to the Vectren/ProLiance agreement, Vectren is guaranteed that its monthly gas supply invoice from ProLiance is assessed charges that reflect only Vectren's original supply plan each day (Vectren Ex. 1, at 21).

Commission Conclusion

Vectren is confident that ProLiance's modifications made at the morning meetings do not adversely affect Vectren's least cost gas supply obligations. The Commission does not share Vectren's confidence and, in any event, Vectren's statement misses the point. If ProLiance were not an affiliate of Vectren, some independent analysis of Vectren's daily gas supply plan and the portfolio manager's modifications would probably be performed to verify and ensure that Vectren's goals continue to be met. We find that such an evaluation is a reasonable and prudent business practice. Thus, we order Vectren to perform such analysis on a daily basis. The next m/p auditor shall evaluate and report on Vectren's follow-up activities in this area.

F. Price Risk Management Techniques

Liberty testified that an especially important dimension of gas supply management is risk management and, more specifically, how a company protects itself from wild or volatile fluctuations in price (Tr. I, 179). The m/p auditor found that Vectren instituted a 'portfolio approach' to gas purchases to mitigate gas price risk and volatility, which includes advance purchases (up to five calendar quarters in advance of delivery), storage gas, first-of-the-month priced gas that is purchased and priced the month prior to delivery, and daily swing purchases at daily index prices (Comm.-Ord. Ex. 2 at II-8). Liberty noted that neither Vectren nor ProLiance (on Vectren's behalf) used any financial instruments to manage price risk and price volatility during the m/p audit period (Id.). Liberty recommends that Vectren specify the parameters to be applied for gas purchases each quarter (Comm.-Ord. Ex. 2 at II-17). Further, the m/p auditor recommends that Vectren examine the prudent use of financial instruments and gas buying tools available on the market for possible implementation. Given Vectren's smaller size and resources, Liberty suggests that Vectren consider including commodity price management as a component of the asset management services bid, or separately issue a bid for commodity price management (Id.).

***33** OCC believes that Vectren has already taken steps to address price risk management, but also believes that further action should be taken particularly because of wholesale price volatility in the summer months (OCC Ex. 1, at 16- 17). OCC recommends that the company's hedging strategy: (1) 'ensure that its dollar cost averaging objective includes all gas purchase requirements including its storage injection volumes'; (2) better specify the procedures for quarterly cost averaging as to volume and timing; and (3) incorporate some limited financial hedging with specified policies to either cap/collar price risk on noncost averaged volumes or take secondary positions for fixed prices purchases when indicated (Id.).

Commission Conclusion

The Commission finds that Vectren has implemented a conservative, modest approach to address gas price risk and price volatility. While the m/p auditor proposes that Vectren issue for bid a request for commodity price management, we are not convinced that such is necessary at this time, although Vectren may choose to do so (given our directives above with regard to the asset management services contract). We do, however, direct Vectren to develop and review purchase parameters for advanced gas purchases at least each quarter. We are concerned about the risk associated with the use of different financial instruments and gas buying tools, such that we will not direct the use of such instruments and tools at this time, as OCC recommended. Vectren should, however, analyze the feasibility and benefits of (and implement such a process for considering) various financial instruments and gas buying tools, and inform the Commission of the analysis and implementation of such project.

G. Lost and Unaccounted for Fuel

We note that the m/p auditor made a recommendation to which we found no direct response from Vectren in its testimony or its briefs. Vectren did state, in its initial brief, that, if it had failed to address a proposal by Liberty, such failure should not be construed as agreement with such proposal (Vectren Br. at 2). Therefore, we consider this item to be contested. The m/p auditor recommended that Vectren assign one individual to be responsible for collection and maintenance of accurate lost and unaccounted for fuel (LAUF) data and minimization of LAUF. Additionally, Liberty contends that Vectren should, commencing October 2003 through September 2004, identify influences of LAUF and consider remedial actions (Comm.-Ord. Ex. 2 at V-2, V-5;). [FN24] OCC further recommends that the Commission allow the parties the right to later review this issue for this m/p audit period because there is an absence of reliable data (OCC Ex. 1, at 8; OCC Br. at 48).

Commission Conclusion

In 03-220, Vectren, OCC and staff addressed this issue in part, agreeing that Vectren has implemented an ongoing program to collect and maintain accurate LAUF data. They deferred the issue of calculating shrinkage costs until the 2004 GCR proceeding. The Commission adopted the 03-220 stipulation on June 30, 2004. Because of Vectren's subsequent agreement involving part of this recommendation and a lack of any direct arguments contrary in this proceeding, we do not believe that Vectren is actually opposing this m/p audit recommendation. We consider this recommendation in this proceeding to be partly resolved, but remain concerned about the fact that reliable data was not available during the m/p audit. We want the next m/p auditor to report on Vectren's actions to identify influences of its LAUF and to consider remedial actions. Also, the next m/p auditor should report on the program Vectren implemented to collect and maintain accurate LAUF data and the issue of calculating shrinkage costs. Only to the extent identified in the prior three sentences is the issue of LAUF remaining open. Staff shall inform the next m/p auditor of this obligation.

VII. SUMMARY OF THE ORDERED ADJUSTMENTS AND ACCUMULATION OF INTEREST

***34** Based upon the foregoing, we conclude that, subject to the following required adjustments, Vectren's GCR rates during the audit periods were fair just and reasonable. The required adjustments are as follows:

\$440,266.00 + interest for the TCO base gas refund retained by ProLiance
800,135.00 + interest for the storage overinjection penalties and interest
3,830,000.00 for the ProLiance asset management contract 1,293,974.00 for the WDS-1 contract 2,132,229.00 for the WDS-2 contract demand and commodity costs and reduced propane inventory 1,093,991.00 for the WDS-3 contract \$9,590,595.00 Total

We note that the first two adjustments in the above list have been expressly agreed upon by Vectren during the course of this proceeding.

OCC has noted that Rule 4901:1-14-05(A) (2) (b), O.A.C., requires Commission-ordered adjustments to include interest at ten percent per annum, plus or minus. Ten percent is a standard interest value and is reasonable in this circumstance. However, given the length of time between the parties' submission of briefs in this matter and the issuance of this decision, we do not believe interest should run from the time of the error until the adjustments are actually given to GCR customers. Rather, interest should run from the time of the error until May 1, 2004.

FINDINGS OF FACT AND CONCLUSIONS OF LAW

(1) Vectren is a natural gas company as defined by Section 4905.03(A)(6), Revised Code, and has rate schedules which contain a purchased gas adjustment clause.

(2) Section 4905.302, Revised Code, and Rule 4901:1-14-08, O.A.C., require this Commission to review the purchased gas adjustment clause contained within the tariffs of each gas and natural gas company on an annual basis unless otherwise ordered by the Commission.

(3) By entry issued September 18, 2002, as amended September 25, 2002, the Commission initiated the current review of Vectren's purchased gas adjustment clause, as defined by Section 4905.302(A)(1)(a), Revised Code, and the m/p audit of Vectren.

(4) Vectren published notice of the hearing in this matter pursuant to Rule 4901-14-08(C), O.A.C., and filed the proofs of publication with the Commission on December 9 and 12, 2003, and January 16, 2004.

(5) D&T conducted the financial audit of Vectren, as required by Section 4905.302(C), Revised Code, and Rule 4901:1-14-07, O.A.C. D&T filed its financial audit report on August 15, 2003.

(6) Liberty conducted the m/p audit of Vectren, as required by Section 4905.302(C), Revised Code, and Rule 4910:1-14-07, O.A.C. Liberty filed its m/p audit report on August 15, 2003.

(7) The hearing in this proceeding commenced on November 20, 2003, at the offices of the Commission. Testimony was taken on November 20 and 21, and December 8, 2003.

(8) Vectren accurately computed its GCR rates in accordance with the provisions of Chapter 4901-1-14, O.A.C., and applied the GCR rates to customer bills during the audit period, except to the extent of the six adjustments required by this decision.

***35** (9) The next auditors should ensure that the adjustments agreed to by Vectren and the adjustments ordered by the Commission (a total of six adjustments) are accurately and correctly calculated and included in the GCR mechanism in future filings.

(10) Vectren shall comply with the m/p audit recommendations to which it has agreed, as clarified by the Commission in Section V of this Order.

(11) It was not prudent, reasonable, or appropriate for Vectren to have executed the Vectren/ProLiance agreement dated October 31, 2000. Vectren's selection of ProLiance as its asset manager without the benefit of a request for competitive bids was not prudent, reasonable, or appropriate at the time.

(12) The terms of the Vectren/ProLiance agreement were not prudent, reasonable, or appropriate during the m/p audit period. Vectren is directed to forthwith issue a request for proposals for an asset management services agreement, which shall include, at a minimum, the management of Vectren's commodity, pipeline capacity, and storage. Additionally, Vectren should be more active to monitor and oversee the asset management services agreement held by a third party (affiliated or unaffiliated). To that end, Vectren should implement an internal audit program; the asset manager should maintain separate records of each Vectren transaction; and Vectren should improve its oversight of the asset manager and performance. In the alternative to competitively bidding the asset management services contract, Vectren can bring the asset management function in-house completely.

(13) Vectren has not maximized the benefits of its propane assets and shall, therefore, conduct a study to better incorporate the use of its propane facilities and file such study with the OCC and Commission within the next six months. The next m/p auditor will evaluate the study and set forth any recommendations.

(14) Vectren shall modify its design day assumptions and inputs to correspond with the recommendations of the m/p auditor in this proceeding. The revisions should be reflected in the next LTFR to be filed with the Commission.

(15) It was not reasonable, prudent or appropriate to execute the WDS-1 contract or the WDS-3 contract at the time Vectren did. Moreover, it was not prudent, reasonable or appropriate for Vectren to have executed the WDS-2 contract or obtained gas under it. Additionally, the entire cost to replace the missing propane inventory should not be borne by the GCR customers.

(16) Vectren's implementation of a five percent reserve margin during the m/p audit period was not reasonable, prudent or appropriate.

(17) Vectren shall, on a daily basis, review modifications made by the asset manager at the morning meetings to ensure that Vectren's least cost gas supply plan is not adversely affected and that Vectren obligations continue to be met.

(18) Vectren's approach to price risk management should be amended to include the development of and review of purchase parameters for advanced gas purchases at least each quarter. Vectren should analyze the feasibility and benefits of (and implement such a process for considering) various financial instruments and gas buying tools and inform the Commission of the analysis and implementation of such project.

***36** (19) The next m/p auditor shall report on Vectren's actions to identify influences of its LAUF and to consider remedial actions. Also, the next m/p auditor shall report on the program Vectren implemented to collect and maintain accurate LAUF data and the issue of calculating shrinkage costs.

(20) Six GCR-rate adjustments are warranted and shall inure to the benefit of the GCR customers. The adjustments are: (a) \$440,266.00 for the TCO base gas refund retained by ProLiance; (b) \$800,135.00 for the storage overinjection penalties and interest; (c) \$3,830,000.00 for the ProLiance asset management contract; (d) \$1,293,974.00 for the WDS-1 contract; (e) \$2,132,229.00 for WDS-2 contract demand and commodity costs and reduced propane inventory; and (f) \$1,093,991.00 for the WDS-3 contract. These adjustments total \$9,590,595.00. In addition, interest at ten percent per annum (as required by Rule 4901:1-14- 05(A) (2) (b), O.A.C.) shall be added from the time of the errors until May 1, 2004. Lastly, the adjustments plus interest should be reflected in the company's filed GCR rate after a ruling upon any applications for rehearing in this proceeding.

ORDER

It is, therefore,

ORDERED, That Vectren's February 11, 2004 motion to strike is denied. It is, further,

ORDERED, That Vectren comply with the m/p audit recommendations to which the company agreed, as clarified by the Commission and set forth in Section V of this Order. It is, further,

ORDERED, That Vectren comply with the conclusions determined to be appropriate by this Commission and set forth in Section VI of this Order. It is, further,

ORDERED, That the auditors selected to conduct the next GCR financial audit and m/p audit of Vectren perform the review and analysis set forth in this Opinion and Order. It is, further,

ORDERED, That adjustments totalling \$9,590,595.00, plus interest at ten percent per annum (from the time of the errors until May 1, 2004) shall be reflected in the company's filed GCR rate after a ruling upon any applications for rehearing in this proceeding. It is, further,

ORDERED, That a copy of this Opinion and Order be served upon Vectren, its counsel, OCC, and all other interested persons of record. Entered in the Journal JUN 14 2005

FOOTNOTES

FN1 Chapter 4901:1-14, O.A.C., was reviewed by the Commission in 2003-2004. In the Matter of the Commission's Review of Its Rules Regarding the Uniform Purchased Gas Adjustment at Chapter 4901:1-14, Ohio Administrative Code, Case No. 03-1384-GA-ORD, Finding and Order (March 11, 2004) and Entry on Rehearing (May 12, 2004). As a result of that review, a number of revisions were made in that chapter and became effective on August 29, 2004. However, those revisions were not in effect during the audit period or hearing period involved in this proceeding. We clarify that all references in this decision to the administrative rules in Chapter 4901:1-14, O.A.C., are to the rules in effect just prior to August 29, 2004.

FN2 Vectren holds a 53 percent interest in the gas assets and is the operator of those assets. Indiana Gas Company Inc. holds a 47 percent interest in the gas assets.

FN3 This is the second financial audit of Vectren since it acquired DP&L's gas

assets and the first m/p audit of Vectren since it acquired DP&L's gas assets.

FN4 Section 4901.16, Revised Code, states: 'Except in his report to the public utilities commission or when called upon to testify in any court or proceeding of the public utilities commission, no employee or agent referred to in section 4905.13 of the Revised Code shall divulge any information acquired by him in respect to the transaction, property, or business of any public utility, while acting or claiming to act as such employee or agent. Whoever violates this section shall be disqualified from acting as agent, or acting in any other capacity under the appointment or employment of the commission.'

FN5 Section 4935.04, Revised Code, was modified during the m/p audit period. The modifications have no impact upon the arguments raised or upon this ruling.

FN6 In Case No. 00-120/00-220, the consolidated GCR audit and LTFR case included a financial audit and an m/p audit of DP&L for the period August 1, 1999 through October 30, 2000, just prior to the date on which DP&L's gas assets were sold to Vectren. The m/p audit in 00-220 was performed by Exeter & Associates Inc. (Exeter). Exeter reviewed the organizational structure, management policies and procedures of Vectren, although the scope of the audit period included only DP&L. Exeter made some specific conclusions and recommendations as to Vectren, including that: (a) Vectren entered into an agreement with ProLiance without the benefit of competitive solicitation; (b) the transportation credit under the Vectren/ProLiance agreement should be increased to \$3.9 million per year to better reflect the value of the capacity assigned to ProLiance; (c) Vectren negotiated the revision of the Vectren/ProLiance agreement to explicitly provide the supplier reservation fee and interstate pipeline capacity costs to be paid by Vectren and how the fee is calculated, and to reflect any discounts to which Vectren is entitled; (d) Vectren should identify any changes to the mix of base load and swing supplies purchased by ProLiance on Vectren's behalf; and (e) the portfolio administration fee of \$450,000 per year is not included in the GCR rates and should not be included in the GCR rates.

FN7 Section 4905.302, Revised Code, was modified on June, 26, 2001, during the middle of the m/p audit period. The change did not impact provision E (instead, provision F was added to the statute) and, thus, the change did not impact the parameters under which the Commission must evaluate Vectren's GCR rates.

FN8 That subsequent financial audit was conducted in In the Matter of the Regulation of the Purchased Gas Adjustment Clause Contained Within the Rate

Schedules of Vectren Energy Delivery of Ohio, Inc. and Related Matters, Case No. 03-220-GA-GCR (03-220).

FN9 CES was later purchased by Enron (Tr. I, 171).

FN10 The DP&L/CES contract involved the same assets and was competitively bid in 1998 (Comm.-Ord. Ex. 2 at II-12). In the year before Vectren acquired the assets, DP&L received \$3.9 million for CES' right to use of DP&L's unutilized assets (Id. at II-13).

FN11 Further details about the propane assets are contained in the next section of this decision.

FN12 Vectren did not pass the cost of that payment on to its GCR customers in GCR rates (Vectren Ex. 6, at 23; Tr. III, 214). But the management fee is included in base rates and, thus, paid by customers (Comm.-Ord. Ex. 2, at II-13, VI-3). OCC's recommendation does not appear to seek a \$450,000 management fee be credited to GCR customers (Tr. II, 142). Rather, OCC seeks to make all ratepayers whole (OCC Ex. 1, at 15).

FN13 OCC actually argues that the transportation credits given during the audit period were too low (by \$660,626.45) because they did not include both the WDS-1 and WDS-2 contracts (OCC Br. at 14-15), but a review of the record illustrates that Vectren did receive the transportation credit for WDS-1 contract, although that portion of the credit was given late and it had not yet been flowed through to GCR customers (Tr. III, 212-213).

FN14 Liberty and OCC admitted that other asset management service providers are or have been subject to state and federal investigations related to the manipulation of energy markets. Some have entered into settlements for damages to resolve disputes related to allegations of manipulation of the energy market and some left the portfolio administration business (Tr. I, 153-157; Tr. II, 49-52, 59, 61-67, 117-118).

FN15 The reduction right terms gave Vectren the right, during part of the contract period, to reduce its capacity portfolio up to specified levels in anticipation of Vectren's customer base switching to competitive suppliers (Vectren Ex. 1, at 5, 13). This allows Vectren to not pay for that capacity and puts ProLiance at risk for

using that capacity.

FN16 For these latter two points, Vectren also strongly criticizes OCC and staff because they agreed in the gas choice program stipulation that the 'ability to exercise the Reduction Rights set forth in its supply agreement with ProLiance Energy, ...appears to be a reasonable approach' and the compensation for Vectren's unutilized pipeline entitlement would 'be evaluated with appropriate consideration being given to the value that [Vectren] also obtains for its customers in terms of the mitigation of stranded costs ...' (Vectren Br. at 29-30). OCC responds that, at the time of the gas choice stipulation, the parties did not positively agree whether there was a value in the reduction rights and OCC has given appropriate consideration to the question in this proceeding. OCC just did not reach Vectren's conclusion for a variety of reasons (OCC Reply Br. 5-6).

FN17 Had Vectren at least put forth a request for proposal or competitively bid the gas assets management services agreement that the company gave to ProLiance, then some market information would have existed from which the Commission could evaluate the reasonableness of the Vectren/ProLiance agreement. That is not to imply that Vectren would have been required to accept any bid for asset management services without considering the bidders integrity and financial stability. Because of the route taken by Vectren, it cannot seriously now complain that the only available competitively bid contracts for the assets at issue are not comparable to the Vectren/ProLiance agreement as to time or terms and conditions.

FN18 Propane can be a peaking service used to meet needs on the coldest days and, therefore, an LDC would want its propane inventory to be full at the start of the heating season (Tr. II, 10). The operation of a propane plant is affected by the ambient air temperature (the warmer temperatures get, there is no need for propane) and the ability to inject propane is dictated by mixing requirements for deliverability into the LDC's system (Tr. II, 79, 249-50; Tr. III, 78; Vectren Ex. 6, at 28). Propane has a higher heating value than gas and must be mixed with air before it is injected into a LDC's system in order to protect certain manufacturing processes and customer appliances. Accordingly, raw propane alone cannot be used to meet system supply requirements (Tr. II, 75, 80; Comm.-Ord. Ex. 2 at II-5).

FN19 'MMcf' stands for a million cubic feet, which is another measure for quantities of gas. One decatherm equals approximately 1.03 Mcf.

FN20 The numerical difference depends upon whether the firm pipeline capacity figure identified in the m/p audit report (Comm.-Ord. Ex. 2 at III-10, III-13) is correctly stated as cubic feet or whether it should be decatherms. In any event, OCC's point

remains the same.

FN21 Vectren also stated that the WDS-1 contract was sought because of the company's supply plan, developed during the summer (Tr. III, 46).

FN22 The staff's brief actually states \$56,4 73, but the correct calculation is \$556,4 37. Staff's dollar figure inadvertently transposed the last two numbers.

FN23 Vectren also raised the issue that one of the members of the m/p auditor team is a partner in Energy Tools, LLC, a consulting firm and marketer of a gas optimization modeling program used by LDCs to evaluate gas supply scenarios. That m/p audit team member was aware that Vectren had used Regional Economic Research for forecasting (Tr. II, 173-174). Vectren argues that these facts imply a conflict of interest for at least one of the m/p auditors.

FN24 Liberty further recommends that the Commission consider an incentive mechanism to ensure accurate reporting of LAUF (Comm.-Ord. Ex. 2 at V-5).

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H

DPUC REVIEW OF THE SOUTHERN CONNECTICUT GAS COMPANY's RATES AND CHARGES, PHASE
 3 - MEGS
 99-04-18RE04

APPLICATION OF CONNECTICUT NATURAL GAS CORPORATION FOR A RATE INCREASE, PHASE
 2 - MEGS
 99-09-03RE09

Connecticut Department of Public Utility Control
 February 10, 2005

SETTLEMENT AGREEMENT BY AND AMONG THE SOUTHERN CONNECTICUT GAS COMPANY, THE
 CONNECTICUT NATURAL GAS CORPORATION, THE OFFICE OF CONSUMER COUNSEL, AND THE
 PROSECUTORIAL DIVISION OF THE DEPARTMENT OF PUBLIC UTILITY CONTROL

WHEREAS, in two separate Decisions, the first dated November 22, 2000, in Docket
 No. 99-04-18PH03, DPUC Review of The Southern Connecticut Gas Company's Rates and
 Charges - Phase 3, and the second Decision dated May 9, 2001, in Docket No.
 99-09-03PH02, Application of Connecticut Natural Gas Corporation for a Rate In-
 crease - Phase 2, the Department of Public Utility Control ("Department") approved
 the concept of Merger Enabled Gas Cost Savings; and

WHEREAS, in its Decision dated November 22, 2000, in Docket No. 99-04- 18PH03,
 DPUC Review of The Southern Connecticut Gas Company's Rates and Charges - Phase
 III (the "SCG IRP Decision"), the Department stated that:

Consistent with the Department's determination that merger enabled non-gas costs
 should be shared between ratepayers and shareholders, the Department will allow
 the sharing of merger-enabled gas-cost savings that result from an approved Gas
 Cost Reduction Plan. These savings which will flow to ratepayers through the PGA
 will be shared in the same proportions as synergy savings in non-gas costs.

Accordingly, the Department will require that the Company file, no later than 60
 days after the issuance of this Decision, a detailed proposal on how merger-en-
 abled gas-supply savings will be identified and quantified....

....

...The Department will consider and rule on the proposed methodology in a com-
 pliance filing.

Merger-enabled gas-cost savings measured under a Department approved method will
 be appropriately netted, on an equivalent basis (i.e., after tax), against earn-
 ings calculated for purposes of the ESM to effectuate a 50/50 sharing of these
 savings; [FN1]

FN1. SCG IRP Decision, at Section IV.A.2.d.

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and

WHEREAS, in its Decision dated May 9, 2001, in Docket No. 99-09-03PH02, Application of Connecticut Natural Gas Corporation for a Rate Increase - Phase II (the "CNG IRP Decision"), the Department stated that:

[C]onsistent with the Department's determination that merger-enabled non-gas costs should be shared between ratepayers and shareholders, the Department will allow the sharing of merger-enabled gas-cost savings that result from an approved Gas Cost Reduction Plan. These savings, which will flow to ratepayers through the PGA, will be shared 50/50 between shareholders and ratepayers. To effectuate this sharing, 50% of after tax merger-enabled gas-cost savings measured under a Department approved method will be allocated to shareholders through the ESM.

Accordingly, the Department will require that the Company file a detailed proposal on how merger-enabled gas-cost savings will be identified and quantified.... [FN2];

FN2. CNG IRP Decision, at Section IV.C.4.

and

WHEREAS, Merger Enabled Gas Cost Savings are gas cost savings arising pursuant to the CNG IRP Decision and the SCG IRP Decision (hereinafter, such savings being referred to as "MEGS"); and

WHEREAS, on February 6, 2001, The Southern Connecticut Gas Company ("SCG" or "Southern"), and on May 23, 2001 the Connecticut Natural Gas Corporation ("CNG") each submitted to the Department its compliance filing proposing how MEGS would be identified and quantified; and

WHEREAS, pursuant to the SCG IRP Decision and the CNG IRP Decision, MEGS will be shared between CNG and SCG shareholders and customers in a manner determined by the Department; and

WHEREAS, it is agreed that CNG, SCG, and the Office of Consumer Counsel ("OCC") have participated in all of the MEGS related proceedings before the Department; and

WHEREAS, by Notice of Continued Hearing dated March 26, 2004, the Department stated that it "has determined that the issues at dispute in these reopened proceedings are extremely complex and can best be resolved through a settlement process," and, on April 2, 2004, in response to requests from SCG and CNG (together, the "Companies," or individually, the "Company") and the OCC, designated the Prosecutorial Division of the Department ("Prosecutorial") to serve jointly as a party in the above-referenced reopened dockets for the purpose of pursuing settlement with the Companies and OCC; and

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WHEREAS, SCG, CNG, the OCC and Prosecutorial (each a "Party" or collectively the "Parties") have negotiated this Settlement Agreement in good faith and to address and permanently resolve outstanding issues relating to MEGS; and

WHEREAS, the Companies each entered into a Gas Portfolio Optimization Agreement with BP Energy Company ("BP") dated March 30, 2001 (the "2001 Optimization Agreements"), which were approved by the Department in its Decision dated June 27, 2001, in Docket No. 01-04-04, Application of Connecticut Natural Gas Corporation and Southern Connecticut Gas Company for Approval of Gas Portfolio Optimization Agreements; and

WHEREAS, the Department stated in its Compliance Filing Response dated November 13, 2001, in Docket Nos. 99-04-18PH03 and 99-09-03PH02, that "the benefits (and costs) flowing from the [2001 Optimization] Agreement[s] are merger-enabled" [FN3] and that "[t]he Companies shall include the net results from the BP [2001] Optimization Agreement[s] as merger-enabled" [FN4];

FN3. Compliance Filing Response, at p. 6.

FN4. Id., at p. 11.

WHEREAS, the Companies renewed their relationships with BP and each entered into a Gas Portfolio Optimization Agreement with BP, dated March 25, 2002, and which expired on March 31, 2004 (the "2002 Optimization Agreements"), and each entered into a subsequent Gas Portfolio Optimization Agreement with BP, dated March 22, 2004, and which will expire on March 31, 2007 (the "2004 Optimization Agreements") (together the 2001, 2002, and 2004 Optimization Agreements are referred to herein as the "BP Optimization Agreements"); and

WHEREAS, pursuant to the Settlement Agreement by and among the OCC and the Companies, approved by the Department in its Decision dated February 22, 2002, in Docket No. 01-10-17, DPUC Review of the Settlement Agreement among the Office of Consumer Counsel, Connecticut Natural Gas Corporation, and The Southern Connecticut Gas Company et al. (the "Settlement Agreement Decision"), "[t]he sharing of merger enabled gas cost changes will occur as a component of the PGA for both Southern and CNG" [FN5] and the Companies' incentive rate plans were extended until September 30, 2005; and

FN5. Settlement Agreement Decision, at Attachment No. 1, Section IV.3.

WHEREAS, the Companies' customers have received 100 percent of all MEGS to date and will continue to receive their shares of MEGS through the purchased gas adjustment clause ("PGA"); and

NOW, THEREFORE, the Parties agree as follows:

1. Resolution of MEGS claims. This Settlement Agreement fully resolves the Com-

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panies' claims to MEGS. The Parties agree and acknowledge that, in full and final resolution of the Companies' claims to MEGS, the Companies are entitled to:

- a. A share of Category 1 MEGS, as described in paragraphs 3 and 4 below;
- b. Category 2 MEGS in the amount listed in Paragraph 5 below; and
- c. A share of the savings from the 2004 Optimization Agreements, as described in Paragraph 4 below.

2. Effective Date. This Agreement shall be effective upon approval by the Department in its entirety without modification.

3. Categories of MEGS. The Companies' shares of MEGS are composed of two categories: Category 1 - MEGS resulting from the BP Optimization Agreements for the period from April 1, 2001 through September 30, 2005; and Category 2 - MEGS resulting from demand savings, the withdrawal of CNG's appeal pursuant to Paragraph 9 of this Agreement, and carrying costs on the Companies' shares that have not been retained by the Companies. In addition to MEGS, the Parties also acknowledge that the Companies are entitled to a share of the savings from the 2004 Optimization Agreements as described in Paragraph 4 below.

4. Category 1 MEGS and shares of Net Savings from the 2004 Optimization Agreements. For the period from April 1, 2001 through and including September 30, 2005, the Companies shall recover 20 percent of the actual net savings from the BP Optimization Agreements, calculated in accordance with Paragraph 6 of this Agreement. The Companies' 20 percent share is comprised of a 15 percent historical incentive plus a 5 percent incremental incentive. Effective October 1, 2005, the Companies' shares of the actual net savings from the 2004 Optimization Agreements calculated in accordance with Paragraph 6 below will utilize the then effective Department approved sharing percentage for **off-system sales**, asset management agreements and **capacity releases**, which is currently 15 percent, [FN6] and each Company shall retain its respective share of the actual net savings and return the customers' share through the PGA. The Parties estimate that the value of the Companies' 5% incremental incentive share of savings from Category 1 MEGS for the period from April 1, 2001 through September 30, 2005 is \$1.1 million, but such estimate is not binding on any Party.

FN6. See Decision, Docket No. 95-02-07, Application of the Connecticut Natural Gas Corporation for a Rate Increase - Phase I (Oct. 13, 1995) at 16; Decision, Docket No. 93-03-09, Application of The Southern Connecticut Gas Company to Increase Its Rates and Charges - Reopening I (Jan. 24, 1996); Docket No. 99-01-09, DPUC Investigation into the Yankee Gas Services Company's Supply Management Agreements (Aug. 18, 1999) at 5; Docket No. 00-02-13, Application of The Southern Connecticut Gas Company for Approval of a Gas Supply Management Agreement (Mar. 15, 2000) at 5.

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5. Category 2 MEGS. CNG shall recover \$1,600,000. SCG shall recover \$1,600,000. These figures represent the total amount of Category 2 MEGS to be received by the Companies.

6. Method of Calculation of BP Optimization Agreement Actual Net Savings. Consistent with the calculation of actual net savings from the BP Optimization Agreements as reported to the Department, the savings from the BP Optimization Agreements will be calculated in accordance with Exhibits C-2 and S-2 of CNG's and SCG's respective BP Optimization Agreements. BP's share of such savings will be deducted to determine the actual net savings from the BP Optimization Agreements as reported to the Department in the Companies' filing of the Quarterly PGA Report for BP Alliance as illustrated in Attachment 1. Nothing in this Agreement shall diminish or interfere with the Department's and the OCC's authority to audit the BP Optimization Agreements to ensure that the savings are calculated in accordance with the BP Optimization Agreements. Nothing in this Agreement is intended to affect in any way the OCC's appeals from the Department Decisions in Docket Nos. 02-10-01, 03-04-01, 03-10-01 and 04-04-01, each a PGA proceeding, or to affect OCC's right to file similar appeals of future PGA proceedings.

7. Method of Recovery of MEGS. Each Company shall recover its share of MEGS for the period from April 1, 2001 through September 30, 2005 in the manner provided herein. Upon the effective date of this Agreement, each Company shall immediately credit the sum of its share of (i) Category 1 MEGS, and (ii) Category 2 MEGS, against its deferred PGA balance as of the first monthly PGA filing. If such Company's deferred balance is not sufficient to cover its share of MEGS through the effective date of this Agreement, then any remaining balance shall be recovered by such Company through a PGA surcharge assessed from the first monthly PGA filing following the effective date of this Agreement through and including September 30, 2005. With respect to Category 1 MEGS from the effective date of this Agreement through September 30, 2005, each Company shall retain its respective 20 percent share of actual net savings and return the customers' 80 percent share of actual net savings to customers through the PGA

8. Secondary Market Transactions. Nothing in this Agreement shall affect or modify the Companies receipt of: (i) the amounts booked for their 15 percent shares of the margins arising from secondary market transactions through the effective date of this Agreement; and (ii) after the effective date of this Agreement, 15 percent or the then effective Department-approved sharing percentage of the margins arising from secondary market transactions from: (A) Canadian gas supply contracts excluded from the 2004 Optimization Agreements pursuant to Section 12.5 of such agreements; (B) downstream resources excluded from the 2004 Optimization Agreements pursuant to Exhibits C-1 and S-1 of CNG's and SCG's respective 2004 Optimization Agreements, and (C) other secondary market transactions that are not included within the 2004 Optimization Agreements. Nothing in this Agreement shall affect or modify OCC's right to contest the Companies' entitlement to receive their shares as described in this paragraph.

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9. Withdrawal of Appeal. Upon the Department's approval of this Agreement, CNG shall withdraw with prejudice: (i) its appeal in Superior Court Docket No. CV-03-0524547-S of the Department's Decision dated October 15, 2003, in Docket No. 99-09-03RE08, Application of Connecticut Natural Gas Corporation for a Rate Increase, Phase I - Interruptible Deferral; and (ii) its declaratory judgment action in Superior Court Docket No. CV-03-0823054-S.

10. Integrated Agreement. This Agreement is the product of settlement negotiations and shall be deemed to be an integrated solution to the issues addressed herein. In the event that the Department does not approve this Agreement in its entirety without modification, this Agreement shall not be binding upon or deemed to represent positions of the Parties, and this Agreement shall be null and void.

11. Acceptance by the Department. If not accepted by the Department in accordance with the provisions hereof, this Agreement shall not prejudice the positions taken by any Party on these issues before the Department in this proceeding and shall not be admissible evidence therein or in any other proceeding before the Department.

12. Cooperative Advocacy. Without reservation or condition, the Parties agree to support this Agreement before the Department and in any related legal proceedings or legislative inquiries or hearings, and to take all action as is necessary on a cooperative basis to secure the expeditious approval and implementation of this Agreement.

13. Reservation of Rights. Other than as expressly stated herein, this Agreement establishes no principles, shall have no precedential effect, and shall not be deemed to foreclose any of the Parties from making any contention in any future proceedings or investigations including, but not limited to, rate cases, performance based rate plans or gas cost incentive mechanisms effective after September 30, 2005. Other than as expressly stated herein, the approval of this Agreement by the Department shall not in any respect constitute a determination as to the merits of any issue in any other proceeding.

14. Merger of Agreement. This Agreement constitutes the entire agreement between the Parties hereto.

IN WITNESS WHEREOF, each of the Parties has duly executed this Agreement as of the date set forth above.

THE SOUTHERN CONNECTICUT GAS COMPANY

By: _____ [Name] [Title]

CONNECTICUT NATURAL GAS CORPORATION

By: _____ [Name] [Title]

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THE OFFICE OF CONSUMER COUNSEL

By: _____ [Name] [Title]

THE PROSECUTORIAL DIVISION OF THE DEPARTMENT OF PUBLIC UTILITY CONTROL

By: _____ [Name] [Title]

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C

Re Berkshire Gas Company
D. T.E. 04-47

Massachusetts Department of Telecommunications and Energy
November 5, 2004

***474** ORDER approving a gas portfolio optimization agreement and a gas sales and purchase agreement executed between a natural gas local distribution company (LDC) and an energy management company.

The agreements with the energy management company, BP Energy Company, are the product of a request for proposals by the LDC, Berkshire Gas Company, in alliance with four other natural gas LDCs that also are regulated subsidiaries of Energy East Corporation.

The optimization agreement is designed to provide a mechanism by which Berkshire will work together with BP to enhance the value of the LDC's gas portfolio. BP will serve as an agent for the LDC and will schedule receipts and deliveries of gas into, and revise nominations from, the LDC's existing portfolio. BP will be compensated based on the incremental ***475** savings above individual benchmarks that Berkshire and its allied LDCs (the Alliance) realize from BP's efforts.

Under the portfolio optimization agreement, BP will provided day-to-day consulting services to Berkshire regarding the use of the LDC's resource portfolio -- including upstream interstate supply, transportation, and underground storage -- to provide reliable and least-cost service to the customers of the LDC. Commodity and capacity contracts approved by the department by prior order will be maintained under the optimization agreement, the pricing provisions of the contracts will not change, and BP will not have the right to renew, modify, or amend any contract or agreement previously entered by Berkshire. Consequently, the LDC will pay no more for natural gas under the optimization agreement than it would have without the agreement and, in fact, is likely to benefit in the form of lower gas supply costs. Department explains that Berkshire can reasonably expect to achieve savings through its participating share in the Alliance, as well as through optimization opportunities available in the market, as affected by liquidity, storage levels, and weather conditions. The LDC is authorized to retain a 25% share of incremental savings generated pursuant to the portfolio optimization agreement.

In evaluating proposals by LDCs for the acquisition of commodity and capacity resources, the department considers whether the acquisition (1) is consistent with portfolio objectives, (2) compares favorably to alternatives with respect to both price and non-price terms, and (3) is the result of a fair, open, and transparent solicitation process.

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P.U.R. Headnote and Classification

1.

GAS
s7

Ma.D.P.U. 2004

[MASS.] Local distribution company -- Obtaining portfolio services -- Coordinated competitive bidding and negotiation process -- Participation of allied local distribution companies -- Selection criteria.

Re Berkshire Gas Company

P.U.R. Headnote and Classification

2.

GAS
s7

Ma.D.P.U. 2004

[MASS.] Local distribution company -- Supply planning -- Gas portfolio optimization agreement -- Purposes and objectives -- Enhanced portfolio value -- Least-cost, reliable gas service.

Re Berkshire Gas Company

P.U.R. Headnote and Classification

3.

GAS
s7

Ma.D.P.U. 2004

[MASS.] Local distribution company -- Supply planning -- Gas portfolio optimization agreement -- Related gas purchase agreement -- Purchasing rights and pricing provisions.

Re Berkshire Gas Company

P.U.R. Headnote and Classification

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4.

GAS
s7

Ma.D.P.U. 2004

[MASS.] Local distribution company -- Resource planning -- Acquisition of commodity and capacity resources -- Standard of review -- Consistent with public interest standard.

Re Berkshire Gas Company

P.U.R. Headnote and Classification

5.

GAS
s7

Ma.D.P.U. 2004

[MASS.] Local distribution company -- Resource planning -- Acquisition of commodity and capacity resources -- Consistent with public interest standard -- Factors considered -- Consistency with portfolio objectives -- Comparison with alternatives -- Fairness of solicitation process.

Re Berkshire Gas Company

P.U.R. Headnote and Classification

6.

GAS
s7

Ma.D.P.U. 2004

[MASS.] Local distribution company -- Resource planning -- Acquisition of commodity and capacity resources -- Portfolio optimization agreement -- Grounds for approval -- Satisfaction of consistent with public interest standard.

Re Berkshire Gas Company

P.U.R. Headnote and Classification

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7.

GAS
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Ma.D.P.U. 2004

[MASS.] Local distribution company -- Resource planning -- Acquisition of commodity and capacity resources -- Portfolio optimization agreement -- Annual reporting requirements.

Re Berkshire Gas Company

P.U.R. Headnote and Classification

***476** 8.

AUTOMATIC ADJUSTMENT CLAUSES
 s32

Ma.D.P.U. 2004

[MASS.] Procurement practices -- Acquisition of commodity and capacity resources -- Portfolio optimization agreement -- Sharing of margins derived from cost savings -- Local distribution company.

Re Berkshire Gas Company

P.U.R. Headnote and Classification

9.

AUTOMATIC ADJUSTMENT CLAUSES
 s28

Ma.D.P.U. 2004

[MASS.] Credits -- Margin sharing -- Savings resulting from portfolio optimization agreement -- Local distribution company.

Re Berkshire Gas Company

P.U.R. Headnote and Classification

10.

AUTOMATIC ADJUSTMENT CLAUSES

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s11

Ma.D.P.U. 2004

[MASS.] Gas adjustment factor -- Local distribution adjustment factor -- Credits -- Margin sharing -- Savings resulting from portfolio optimization agreement -- Local distribution company.

Re Berkshire Gas Company

P.U.R. Headnote and Classification

11.

GAS
s7

Ma.D.P.U. 2004

[MASS.] Local distribution company -- Resource planning -- Acquisition of commodity and capacity resources -- Portfolio optimization agreement -- Margin sharing.

Re Berkshire Gas Company

P.U.R. Headnote and Classification

12.

AUTOMATIC ADJUSTMENT CLAUSES
s17

Ma.D.P.U. 2004

[MASS.] Indirect costs -- Legal fees associated with procurement of gas supplies -- Inappropriate collection through gas adjustment factor (em Refund requirement - - Natural gas local distribution company.

Re Berkshire Gas Company

P.U.R. Headnote and Classification

13.

AUTOMATIC ADJUSTMENT CLAUSES

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Ma.D.P.U. 2004

[MASS.] Refunds -- Inappropriate collections -- Legal fees associated with procurement of gas supplies -- Natural gas local distribution company.

Re Berkshire Gas Company

P.U.R. Headnote and Classification

14.

GAS
 s7

Ma.D.P.U. 2004

[MASS.] Local distribution company -- Resource acquisitions -- Gas purchase agreement -- Grounds for approval -- Consistent with public interest.

Re Berkshire Gas Company

APPEARANCES: James M. Avery, Esq., Brown, Rudnick, Berlack, Israel, LLP, One Financial Center, Boston, Massachusetts 02111, FOR: The Berkshire Gas Company, Petitioner, Thomas F. Reilly, Attorney General, BY: Karlen J. Reed, Assistant Attorney General, One Ashburton Place, Boston, Massachusetts 02108, Intervenor, John K. Habib, Esq., Keegan, Werlin & Pabian, LLP, 265 Franklin Street, Boston, Massachusetts 02110, FOR: NSTAR Gas Company, Limited Participant

Before Afonso, chairman and Connelly, Keating, Sullivan, Jr. and Manning, commissioners.

BY THE COMMISSION:

I. INTRODUCTION

On April 27, 2004, The Berkshire Gas Company [FN1] ('Berkshire' or 'Company'), pursuant to G.L. c. 164, §§ 76 and 94A, submitted for approval by the Department of Telecommunications and Energy ('Department') a gas portfolio and optimization agreement ('Optimization Agreement') and a gas sales and purchase agreement ('Purchase Agreement') executed with BP Energy Company ('BP'). The Department has approved similar agreements in Berkshire Gas Company, D.T.E. 01-41 (2001) ('2001 Optimization Agreement') and Berkshire Gas Company, D.T.E. 02-19 (2002) ('2002 Optimization Agreement'). The Company's proposal was docketed as D.T.E. 04-47.

On July 23, 2004, pursuant to notice duly issued, the Department conducted a public hearing to afford interested persons the opportunity to comment on the Com-

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pany's proposal. The *477 Attorney General of the Commonwealth ('Attorney General') intervened as of right, pursuant to G.L. 12, § 11E, and the Department granted NSTAR Gas Company's motion for limited participant status.

On September 9, 2004, the Department held an evidentiary hearing. The Company presented the testimony of Karen Zink, president, chief operating officer, and treasurer of Berkshire. The Company and Attorney General submitted initial briefs on September 24, 2004, reply briefs on October 1, 2004, and supplemental briefs on October 8, 2004. [FN2] The evidentiary record consists of 147 exhibits and eleven record requests.

II. DESCRIPTION OF THE PROPOSED AGREEMENTS

A. Request for Proposals Process

[1, 2] The Optimization Agreement is the product of a coordinated effort by Berkshire and four other natural gas local distribution companies ('LDCs') that are regulated subsidiaries of Energy East Corporation ('Energy East ') (collectively, 'Alliance') (Exh. BG-2, at 3). [FN3] The Optimization Agreement and Purchase Agreement were executed after issuance of a Joint RFP by the Alliance (id.). The members of the Alliance issued a Joint RFP to 16 potential bidders on November 13, 2003 (Exhs. BG-2, at 7-8; AG 1-19 (confidential); AG 1-39). In December 2003, the Alliance received responses from eleven companies (Exh. BG-2, at 8). The Joint RFP had the following objectives: (1) to secure a strategic alliance that would leverage the gas supply expertise and resources of members of the Alliance with a respondent's supply capability and expertise, marketing and optimization knowledge, financial products, and information technology; (2) assist the Alliance in maximizing value from gas storage optimization services; (3) provide gas supply arrangements in various supply areas, including gas supply contracts designed to preserve reliability and flexibility while extracting value from optimization techniques; and (4) provide short term gas purchase, balancing and/or capacity arrangements whereby an entity buys services from the members of the Alliance, including delivered city gate supply and market area/city gate balancing services (Exh. AG 1-19 (Att. B) (confidential)).

Bids were evaluated based on price and non-price factors (Exh. AG 1-20). Non-price factors included: (1) the capability to perform the required services; (2) the availability of reliable supplies necessary to meet the Alliance's supply requirements; (3) organizational experience in portfolio services, achievement of savings, and back office capability; (4) the financial strength of the respondent and the ability to provide satisfactory credit support; (5) the ability to manage financial and physical risk; and (6) the expected level of savings to be realized by the Alliance and their customers (id.).

Following the initial evaluation of the bids, the Alliance selected four respondents for further discussion (Exhs. BG-2, at 8; AG 1-20). According to Berkshire,

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BP's proposal, its experience working with the Alliance, and the system that was already in place, made BP the final candidate for negotiation (Exh. BG-2, at 8). Following the negotiations, the Alliance selected BP as the winning bidder (id.).

Berkshire states that it did not issue an individual RFP for portfolio services because the Company received a very limited response to a company-specific RFP in 2002 (id. at 7). Consequently, the Company determined that it was more appropriate and cost-beneficial to participate in a coordinated competitive bidding and negotiation process with the other Energy East LDC's (Exhs. DTE 1-19; AG 1-19 (confidential)).

Berkshire argues that the Joint RFP process was substantially similar to the processes followed by the Company and approved by the Department in 2001 and 2002 (Exh. BG-2, at 7-8). The Company argues that the competitive solicitation process was fair, open, transparent, and complied with Department standards (Company Brief at 4). According to Berkshire, the nature of the solicitation was clear to potential bidders and bidders were afforded an opportunity to ask questions or seek clarification of the Joint RFP (id. at 7, citing Exh. AG 1-19 (Att. *478 C)). The Company states that the Alliance did not receive any objections or complaints from bidders regarding the competitiveness, fairness, or transparency of the Joint RFP process (Exh. DTE 1-19; Company Brief at 7, citing AG-1-19 (Att. C)).

Berkshire contends that the Alliance properly determined that the BP's proposal was superior to the alternative proposals with respect to both price and non-price factors (Company Brief at 7-8, citing Exhs. BG-1, at 89; AG 1-26; AG 1-37; Tr. at 147-49). In addition, Berkshire argues that BP's proposal presented the best opportunity for the Company to manage its resources in order to reduce gas costs for customers (id., citing Exhs. BG-1, at 89; AG 1-26; AG 1-37; Tr. at 147-49). The Company states that BP maintains a strong credit rating, which is important to avoid the operational and control-related concerns associated with the insolvency or bankruptcy of an asset manager (id. at 8; citing Exh. DTE 1-27). The Attorney General did not address this issue in his brief.

B. Optimization Agreement

The Optimization Agreement is for a three-year term through and including March 31, 2007, unless Berkshire or BP terminate the contract for any of the specified reasons provided for in the agreement (Exh. BG-4, §§ 3.2, 3.4, 3.6). [FN4] The Optimization Agreement is designed to provide a mechanism by which Berkshire will work together with BP to enhance the value of the Company's gas portfolio (including transportation, storage, and purchase and sale of natural gas) and to provide Berkshire's customers with least-cost, reliable gas service (Exhs. BG-2, at 3-4; BG-4, § 2.1). Pursuant to the Optimization Agreement, BP will serve as Berkshire's agent and will schedule receipts and deliveries of gas into, and revise nominations from, Berkshire's existing portfolio (Exh. BG-4, § 2.4). The Optimization Agreement specifies that the commodity cost of gas will be determined

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by the least-cost routing of the gas (id. at § 12.1). [FN5]

Berkshire's gas costs savings are based on the Company's participation share in the Alliance (Exh. BG-3, § 4.2 (confidential)). Similarly, the Optimization Agreement provides that BP will be compensated based on the incremental savings above individual benchmarks that Berkshire and the other Alliance LDCs realize from BP's efforts (Exh. BG-4, § 4.3). [FN6]

The current Optimization Agreement is similar in structure to the previously approved 2001 Optimization Agreement and 2002 Optimization Agreement (Exh. BG-2, at 3-4). Specifically Berkshire will continue to: (1) retain full control of its gas supply, transportation and storage assets, and all downstream resources including liquefied natural gas ('LNG'); (2) have access to various price stability tools; and (3) purchase gas on a least-cost basis, which will allow for continued access to existing supply contracts that contain lower prices (id. at 10).

Pursuant to the Optimization Agreement, a transaction book has been created to record all portfolio transactions (Exh. BG-4, § 2.3). The transaction book will be maintained by BP in a manner that permits the identification of all savings under the Optimization Agreement (id.). The Company will coordinate transactions with the other members of the Alliance through daily conference calls and meetings to ensure that savings are properly allocated to the respective companies (Exh. AG 1-17). In addition, each party to the Optimization Agreement will have the right to inspect and examine the transaction book, together with other books, records, reports, charts, and documents used in connection with the performance of duties and obligations under the Optimization Agreement, to verify the services rendered, processes employed, savings generated, and the accuracy of any billings or information related to the Optimization Agreement (Exh. BG-4, § 11.1).

C. Margin Sharing

The Company proposes to retain 25 percent of the incremental savings generated pursuant to the Optimization Agreement (Exh. BG-2, at 11-12). Specifically, the Company proposes to track all transactions and classify each ***479** according to the categories described in Interruptible Transportation/Capacity Release, D.T.E. 93-141-A (1996) (i.e., interruptible sales, **capacity release**, interruptible transportation, and **off-system sales**). The Company proposed to retain 25 **percent** of the savings achieved in each category (id.). Alternatively, the Company proposes to retain 25 percent of all incremental savings on an aggregate basis (id. at 12). Under either alternative, the total amount of savings will be the same.

D. Legal Bills

Berkshire paid \$118,000 for legal services rendered in connection with the execution and approval of the 2002 Optimization Agreement (Exh. AG 1-78 (confidential)). This amount has been collected through Berkshire's GAF (id.).

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E. Purchase Agreement

[3] Berkshire's proposed Purchase Agreement operates in conjunction with the Optimization Agreement (Exh. BG-6). Under the Purchase Agreement, BP will provide the Company's Gulf Coast production area gas requirements, as well as other quantities of gas that BP and the Alliance mutually agree upon (id.). The Purchase Agreement further provides that if Berkshire learns of the availability of Gulf Coast gas cheaper than that provided for under the Purchase Agreement, the Company has the right to buy the cheaper gas and BP has no right to match the lower cost (Exhs. BG-6, Art. IV; BG-4, § 2.7). Pricing under the Purchase Agreement is based on market indices and a supply reservation charge (Exh. BG-5, Art. V (confidential)). Finally, the Optimization Agreement provides that Berkshire must satisfy its purchase obligations under the Company's other gas supply agreements in its portfolio before purchasing gas from BP (Exh. BG-4, § 2.7).

III. POSITIONS OF THE PARTIES

A. Request for Proposals Process

Berkshire states that it did not issue an individual RFP for portfolio services because the Company received a very limited response to a company-specific RFP in 2002 (id. at 7). Consequently, the Company determined that it was more appropriate and cost-beneficial to participate in a coordinated competitive bidding and negotiation process with the other Alliance LDC's (Exhs. DTE 1-19; AG 1-19 (confidential)).

Berkshire argues that the Joint RFP process was substantially similar to the processes followed by the Company and approved by the Department in 2001 and 2002 (Exh. BG-2, at 7-8). The Company argues that the competitive solicitation process was fair, open, transparent, and complied with Department standards (Company Brief at 4). According to Berkshire, the nature of the solicitation was clear to potential bidders and bidders were afforded an opportunity to ask questions or seek clarification of the Joint RFP (id. at 7, citing Exh. AG 1-19 (Att. C)). The Company states that the Alliance did not receive any objections or complaints from bidders regarding the competitiveness, fairness, or transparency of the Joint RFP process (Exh. DTE 1-19; Company Brief at 7, citing AG-1-19 (Att. C)).

Berkshire contends that the Alliance properly determined that the BP's proposal was superior to the alternative proposals with respect to both price and non-price factors (Company Brief at 7-8, citing Exhs. BG-1, at 89; AG 1-26; AG 1-37; Tr. at 147-49). In addition, Berkshire argues that BP's proposal presented the best opportunity for the Company to manage its resources in order to reduce gas costs for customers (id., citing Exhs. BG-1, at 89; AG 1-26; AG 1-37; Tr. at 147-49). The Company states that BP maintains a strong credit rating, which is important to avoid the operational and control-related concerns associated with the insolvency or bankruptcy of an asset manager (id. at 8, citing Exh. DTE 1-27). The Attorney

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General did not address this issue in his brief.

B. Optimization Agreement

1. Berkshire

***480** Berkshire claims that the Attorney General's arguments concerning the Optimization Agreement are misleading, erroneous, and not supported by evidence (Company Reply Brief at 2). The Company asserts that the Optimization Agreement is consistent with Department precedent (Company Brief at 10, 22). The Company argues that many provisions of the Optimization Agreement and the Company's overall re-source plan have been previously approved by the Department (id. at 15-16, citing Berkshire Gas Company, D.T.E. 02-17; D.T.E. 01-41, at 11; D.T.E. 02-19; Berkshire Gas Company; D.T.E. 98-99 (1999)).

The Company argues that a three-year term is appropriate because (1) the Alliance has had three years experience working with BP, (2) the present Optimization Agreement is materially the same as the previous agreements, and (3) a three-year term provides continuity and avoids the start-up issues associated with a new Alliance partner (Company Brief at 10). According to the Company, compared to an asset management arrangement, the Optimization Agreement provides the maximum opportunity for Berkshire to achieve savings for its customers (id. at 17, citing Exhs. BG-3, Art. IV; BG-1, at 6, 9; Tr. at 56).

Berkshire claims that the Optimization Agreement will produce additional savings over and above those levels achievable by the Company alone (Company Brief at 11, 13, 18, citing Exh. BG-3, Art. IV; D.T.E. 02-19, at 14). Berkshire contends that, even if no savings are realized, BP will make guaranteed payments to the Company and the other Alliance LDCs and Berkshire will only pay BP for the commodity cost of the gas (id. at 12, citing Exhs. BG-1, at 9; BG-3, Art. IV; D.T.E. 02-19, at 17, n.13). Further, Berkshire asserts that the Optimization Agreement is structured to ensure that BP has an appropriate incentive to maximize the Company's savings and help it obtain natural gas at the lowest possible cost (id. at 12).

Berkshire argues that the Optimization Agreement imposes no additional risks on the Company or its customers (id. at 18). The Company states that the Optimization Agreement requires the purchase price of natural gas to be at the lowest available marginal commodity cost and that Berkshire will not pay more for natural gas under the Optimization Agreement than it would have without the Optimization Agreement (id., citing Exhs. BG-3, Arts. XII, XIII; B-2; D.T.E. 01-41, at 11-12; D.T.E. 02-19, at 16).

The Company contends that, despite the Attorney General's claims to the contrary, Berkshire has adequately complied with all Department reporting requirements (Company Reply Brief at 8, citing Attorney General Brief at 4). Berkshire asserts that the Company will continue to retain control over its resources and dispatch decisions on a daily basis (Company Brief at 16). The Company states that it will

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continue to review weather forecasts, and evaluate load requirements, storage inventories, market conditions, and conditions on the Tennessee Gas pipeline to ensure that gas is dispatched on a least-cost basis and that service reliability is maintained (*id.*, citing Exh. DTE 1- 16). Further, the Company states that it will continue to review with the Alliance daily how much gas is required for the day and discuss opportunities available to optimize the portfolio (*id.* at 16, citing Exhs. AG 1-17; AG 1-22 (Att. B)). In addition, the Company states that it will monitor and review transactions under the Optimization Agreement on a daily basis to ensure that the needs of its customers are met (*id.*).

Berkshire argues that, contrary to the Attorney General's contention, it has correctly interpreted and applied the Department's precedent concerning derivatives (Company Reply Brief at 9, n.11 citing Attorney General Brief at 5, n.7). The Company maintains that it will not engage in any speculative financial arrangements under the Optimization Agreement (Company Brief at 19, citing Exhs. BG-3, exh. B-3 (confidential)). The Company states that it will continue to comply with the Department's directives with respect to any speculative financial arrangements (*id.*, citing D.T.E. 02-19, D.T.E. 01- 41).

With regard to the Attorney General's assertion that BP's reporting procedures under the previous agreements were lacking, Berkshire states that the Company has recognized ***481** the need for more timely and complete documentation of portfolio optimization activity (Company Reply Brief at 9). Accordingly, the Company states that its operating procedures with BP were revised to include many of the specific enhancements suggested in the 2002 Audit (Company Brief at 21, citing Exhs. AG 1-22 (Att. A) (confidential); DTE 1-25 (Supp.) (confidential)). Finally, Berkshire states that it needed more time to complete its 2002 annual report and that it alerted the Department about the delay (Company Reply Brief at 9, citing Tr. at 85-86).

2. Attorney General

The Attorney General argues that the Optimization Agreement is not in the public interest and, therefore, urges the Department to reject it (Attorney General Brief at 4-8). Specifically, the Attorney General contends that Berkshire lacks the necessary internal and external control mechanisms to prevent BP from using derivative transactions under the Optimization Agreement for speculative purposes (*id.* at 4-5). [FN7] The Attorney General states that Energy East's derivatives policy has not been explicitly examined or approved by the Department (*id.* at 5, citing Exh. BG-4, §§ 2.6, 6.2(c) at 37; Attorney General Supplemental Brief at 1). In addition, the Attorney General claims that the Optimization Agreement does not require BP to retain and provide complete, detailed information regarding its derivative activity to Energy East's audit committee for review (Attorney General Brief at 5). According to the Attorney General, the lack of an internal control mechanism over BP's derivative transactions will expose the Company's ratepayers to the risk of harm from BP's poor financial decisions (*id.* at 7-8, citing Berkshire Gas

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Company, D.T.E. 03-89, at 31-32 (2004)). Moreover, the Attorney General argues that Energy East's 2002 Audit is inconclusive as to whether BP has acted in Berkshire's ratepayers' interests (Attorney General Supplemental Brief at 1).

The Attorney General also argues that the Optimization Agreement is not in the public interest because the allocation of savings favors BP at the expense of Berkshire and its customers (Attorney General Brief at 6). The Attorney General contends that, under the 2001 Optimization Agreement and 2002 the Optimization Agreement, BP was allowed to retain monetary benefits even as Berkshire's savings were reduced (*id.*). The Attorney General argues that the same could happen under the present Optimization Agreement because Berkshire agreed to accept less in terms of minimum guaranteed savings than the Company was entitled to under the 2002 Optimization Agreement (*id.* at 6, citing Exh. AG 1-2 (confidential)). Finally, the Attorney General claims that the Optimization Agreement exposes the Company's ratepayers to 'an elevated risk of harm' because, under the scope of the agency provisions, Berkshire can be held responsible for BP's actions for the three-year term of the agreement (*id.*, citing Exh. BG-4, § 2.4).

Alternatively, the Attorney General argues that, if the Department approves the Optimization Agreement, the approval should be conditioned on Berkshire instituting policies to protect the Company's ratepayers (Attorney General Brief at 8). The Attorney General suggests that the Department should require Berkshire to: (1) engage an independent auditor to determine that all transactions under the proposed Optimization agreement, including BP's derivative activities, and allocations are made in the best interest of the Company's customers; (2) file annual reports with the Department in a timely manner; [FN8] (3) seek prior approval from the Department for all proposed substantive changes to the Optimization Agreement and related agreements; [FN9] (4) conduct a comprehensive external audit of all BP transactions under the 2001 Optimization Agreement and 2002 Optimization Agreement to determine whether the activities BP and the Alliance performed were consistent with Department orders and precedent, and were in the best interests of the Company's customers; (5) report the amount of Berkshire's gas subjected to the demand/reservation charge and assess whether the amount resulted in least-cost pricing for Berkshire's customers; (6) increase the weighting of the back office system category [FN10] in any future *482 Joint RFP; (7) update the Department annually on BP's enhancements to correct deficiencies in its back office systems; and (8) submit a final external, independent audit report to the Department prior to seeking a renewal or extension of the Optimization Agreement or before Berkshire issues any additional request for proposals ('RFP ') to optimize the Company's gas supply assets (Attorney General Brief at 8-9; Attorney General Supplemental Brief at 1).

C. Margin Sharing

1. Berkshire

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Berkshire claims that it has worked creatively to establish the Alliance to maximize the overall benefit to ratepayers, and that the opportunity to share margins is an appropriate reward for its aggressive pursuit of optimization opportunities (Company Brief at 23). According to Berkshire, transactions conducted under the Optimization Agreement are the same type of transactions described in D.T.E. 93-141-A and, therefore, the Department should apply its established margin-sharing principles to any savings generated by the portfolio optimization activities (id., citing Exh. BG-1, at 11-12).

The Company disputes the Attorney General's comparison of Optimization Agreement activities to price-volatility mitigation efforts (Company Reply Brief at 15-16). Rather, the Company argues that optimization does not reduce volatility (id. at 16). The Company states that its margin-sharing proposal is consistent with its goal to generate and return margins to ratepayers (id.). Finally, the Company argues that its margin-sharing proposal is consistent with the criteria cited by the Attorney General as pre-requisites for incentive recovery (id. at 17-18, citing Attorney General Brief at 14).

2. Attorney General

The Attorney General states that the Department should not approve Berkshire's margin-sharing proposal (Attorney General Brief at 14; Attorney General Reply Brief at 4). The Attorney General argues that the Department has approved margin sharing for only four categories of revenues (i.e., interruptible sales, capacity release, interruptible transportation, and off-system sales), and not for savings associated with a portfolio optimization agreement (Attorney General Brief at 9-10; Attorney General Reply Brief at 4).

The Attorney General contends the Department should reject Berkshire's margin-sharing proposal because, under the optimization agreement, the participants share both the costs and the benefits. Although the Company argues that the Optimization Agreement is similar to capacity management agreement, where the Department has approved margin sharing, the Attorney General disagrees. Specifically, with a capacity release, agreement, the Attorney General argues that the LDC receives a fixed price for the sale of an asset and bears no costs associated with capacity (id. at 12).

In addition, the Attorney General states that the Department has rejected the use of incentive hedging as a means to reduce price volatility, in part because incentives could negatively affect the development of retail competition (id. at 10-11, citing Risk Management Techniques, D.T.E. 01-100-A at 24 (2002)). The Attorney General asserts that, because one of the expected benefits of the Optimization Agreement is enhanced risk management and price stability, the Department must reject the margin-sharing proposal (id. at 11).

Alternatively, the Attorney General asserts that if Berkshire's margin-sharing

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proposal is approved, the Department should ensure that the Company earns such incentives only when: (1) the Company clearly demonstrates that there are proven benefits to ratepayers; (2) the Company conducts an independent assessment that shows the activities being encouraged have been reported accurately; (3) the activities are done for the benefit of the Company's ratepayers; and (4) any program that incorporates incentives also ensures that ratepayers receive safe, reliable, least-cost service (id. at 14).

D. Legal Bills

1. Berkshire

***483** Berkshire states that because it had an existing gas asset management plan in place during the test year for its last rate case, the Company did not seek to recover legal costs for gas acquisition activities at that time (Company Reply Brief at 19-20, citing Tr. at 173-175; Berkshire Gas Company, D.T.E. 99-81 (1999)). Therefore, Berkshire argues that the Company's base rates do not recover any costs associated with gas optimization activities and that to preclude recovery of legal costs related to the 2002 Optimization Agreement would have the effect of punishing Berkshire for pursuing optimization opportunities (id. at 18-21). Further, Berkshire argues that its cost of gas adjustment clause ('CGAC') tariff permits recovery for expenses for procuring gas supplies, so long as costs recoverable through the CGAC are not also in base rates (id. at 21). Therefore, Berkshire contends that legal costs related to the 2002 Optimization Agreement were appropriately recovered through its CGAC (id.).

2. Attorney General

The Attorney General objects to Berkshire's recovery of legal fees rendered in connection with the 2002 Optimization Agreement. The Attorney General states that Berkshire's recoverable gas acquisition costs and legal fees were determined in the Company's last rate case and that this amount was allocated between base rates and the gas adjustment factor ('GAF') (Attorney General Brief at 15). Therefore, by including legal costs related to the 2002 Optimization Agreement in its GAF, the Attorney General contends that the Company has inappropriately increased its GAF by \$118,000 (Attorney General Brief at 15-16; Attorney General Reply Brief at 4-5).

The Attorney General disputes Berkshire's contention that legal fees were approved when the Department approved the Company's GAF for 2003 and 2004 (Attorney General Reply Brief at 4, citing Western Massachusetts Electric Company, D.T.E. 03-34, at 6 (2004); Boston Gas Company, D.P.U. 96-50-C (Phase I) at 33 (1997), citing Robinson v. Department of Public Utilities, 416 Mass. 668, 673 (1993), NYNEX, D.P.U. 94-50, at 444 (1995); Fitchburg Gas and Electric Light Company, D.T.E. 99-66-A at 24 (2001)). Accordingly, the Attorney General argues that the Department should direct Berkshire to recalculate its GAF reconciliations for 2003

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and 2004 to remove the \$118,000 in legal fees, and refund this amount with interest in the Company's next GAF filing (Attorney General Brief at 15-16; Attorney General Reply Brief at 4-5).

E. Purchase Agreement

Berkshire argues that the Purchase Agreement is in the public interest because it provides a least-cost, flexible resource, enabling the Company refine its supply portfolio (Company Brief at 14). Specifically, Berkshire asserts that the Purchase Agreement provides the Company with greater flexibility to procure Gulf Coast gas more cheaply (id.). Finally, Berkshire argues that the Purchase Agreement helps the Company maintain reliability due to the vast resources of BP (id. at 15). The Attorney General did not address this issue.

IV. STANDARD OF REVIEW

[4, 5] In evaluating a gas utility's resource options for the acquisition of commodity resources as well as for the acquisition of capacity under G.L. c. 164, § 94A ('Section 94A'), the Department examines whether the acquisition of the resource is consistent with the public interest. Commonwealth Gas Company, D.P.U. 94-174-A at 27 (1996). In order to demonstrate that the proposed acquisition of a resource that provides commodity and/or incremental resources is consistent with the public interest, an LDC must show that the acquisition (1) is consistent with the company's portfolio objectives and (2) compares favorably to the range of alternative options reasonably available to the company and its customers, including releasing capacity to customers migrating to transportation, at the time of the acquisition or contract negotiation. Id.

In establishing that a resource is consistent with the company's portfolio objectives, the ***484** company may refer to the portfolio objectives established in a recently approved forecast and requirements plan or in a recent review of supply contracts under Section 94A, or may describe its objectives in the filing accompanying the resource proposal. Id. In comparing the proposed resource acquisition to current market offerings, the Department examines relevant price and non-price attributes of each contract to ensure a contribution to the strength of the overall supply portfolio. Id. at 28. As part of the review of price and non-price attributes, the Department considers whether the pricing terms are competitive with those of the broad range of capacity, storage, and commodity options that were available to the LDC at the time of the acquisition, as well as those opportunities that were available to other LDCs in the region. Id. In addition, the Department determines whether the acquisition satisfies the LDC's non-price objectives, including, but not limited to, flexibility of nominations and reliability and diversity of supplies. Id. at 29. In making these determinations, the Department considers whether the LDC used a competitive solicitation process that was fair, open and transparent. The Berkshire Gas Company, D.T.E. 02-56, at 9; Bay State Gas Company, D.T.E. 02-52, at 8 (2002); KeySpan Energy Delivery New England,

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D.T.E. 02-54, at 9 (2002); The Berkshire Gas Company, D.T.E. 02- 19, at 11 (2002).

V. ANALYSIS AND FINDINGS

A. Request for Proposals Process

A RFP process is acceptable if the process was 'fair, open and transparent.' D.T.E. 98-32-B at 54-55. The Department approved the RFP processes used by the Company in 2001 and 2002, finding that the processes were appropriately conducted, fair, open, and transparent. D.T.E. 01-41, at 14, and D.T.E. 02-19, at 11. In the instant proceeding, the bid solicitation and evaluation process was similar to the processes approved in D.T.E. 01-41 and D.T.E. 02-19. The Joint RFP evaluation process was clearly explained to each potential bidder and evaluation criteria were provided. Bidders were given the opportunity to request clarification of the evaluation criteria and the Joint RFP process itself (Exh. AG 1-19 (confidential)). In addition, bids were evaluated and the winning bid was selected based on the criteria set forth in the Joint RFP (id.). Further, no objection to the Joint RFP process was raised by bidders or potential bidders (id.). Accordingly, the Department finds that the Joint RFP process conducted by Berkshire and the Alliance was open, fair, transparent and, therefore, acceptable.

B. Optimization Agreement

[6, 7] The Department's review of Berkshire's proposal indicates that the Optimization Agreement is consistent with the portfolio objectives presented in the Company's most recent forecast and supply plan approved by the Department in Berkshire Gas Company, D.T.E. 02-17 (2003). In addition we find that the Optimization Agreement with BP compares favorably to the range of alternatives available to Berkshire and its customers. Under the proposed Optimization Agreement, BP will provide day-to-day consulting services to Berkshire regarding the use of the Company's resource portfolio, including upstream interstate supply, transportation, and underground storage, to provide reliable and least-cost service to its customers (Exhs. BG-2, at 3-4; BG-4, §§ 2.1, 2.4). The commodity and capacity contracts approved by the Department in D.T.E. 02-17 will be maintained under the proposed Optimization Agreement. Moreover, the pricing provisions of these contracts will not change under the Optimization Agreement and BP will not have the right to terminate, renew, modify, or amend any contract or agreement previously entered into by Berkshire (Exhs. BG-4, § 2.4; DTE 1-5; Tr. at 69-71). In addition, BP will not have the exclusive right to supply Gulf Coast production gas by matching lower prices offered by an alternative supplier and BP will not play a role in negotiating any new contracts that the Company might enter into with third parties (Exhs. BG-2, at 10; BG-4, §§ 2.4, 2.7; DTE 1-5; Tr. at 69-71).

***485** Therefore, even in the absence of savings from the proposed Optimization Agreement, Berkshire's resource portfolio will still be least-cost and the Company's customers will pay no more for natural gas under the Optimization Agreement

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than they would have without it. (Exh. BG-4, § 12.1). In fact, the Optimization Agreement is likely to benefit Berkshire's customers in the form of lower gas supply costs. [FN11]

The Attorney General argues that the present agreement is less favorable to Berkshire's customers when compared to the 2002 Optimization Agreement because the Company has agreed to accept less in terms of minimum guaranteed savings (Attorney General Brief at 6). The savings Berkshire can reasonably expect to achieve are determined by the Company's participating share in the Alliance, as well as optimization opportunities available in the market, as affected by liquidity, storage levels, and weather conditions (Exhs. DTE 1-9 (confidential); AG 1-7; AG 1-8). [FN12] Berkshire's participating share in the Alliance decreased from 6.67 percent in 2002 to 6.0 percent, largely as a result of Rochester Gas and Electric Corporation's addition to the Alliance (Exh. BG-2, at 3; Tr. at 92-95). [FN13] Also, the downward adjustment of the aggregate minimum guaranteed savings was based on BP's assessment of market conditions (Exh. BG-1, at 10). Therefore, we find that the minimum guaranteed savings under the present Optimization Agreement are reasonable.

In addition, the Attorney General contends that the Optimization Agreement exposes Berkshire's customers to 'an elevated risk of harm' (Attorney General Brief at 6). We disagree. The terms of the proposed Optimization Agreement are substantially similar to the 2001 Optimization Agreement and 2002 Optimization Agreement, therefore, any risks to Berkshire's customers will not be higher than they were under the previous agreements (Exh. BG-2, at 10; AG 1-27). Moreover, Berkshire will incur no costs from any transactions entered into by BP under the proposed Optimization Agreement (Exhs. DTE 1-1; DTE 1-14). Further, the Company has confirmed that it will not engage in any speculative financial arrangements under the Optimization Agreement and it will comply with all prior Department directives with respect to any speculative financial transactions (Exhs. BG-3, exh. B-3 (confidential); DTE 1-14). Therefore, we find that the Optimization Agreement does not expose Berkshire's customers to an elevated risk of harm. Because the Optimization Agreement is consistent with the Company's resource portfolio objectives and compares favorably to the range of alternatives reasonably available to the Company and its customers, the Department finds that the Optimization Agreement is consistent with the public interest and is approved. [FN14]

With regard to the Attorney General's concerns about Energy East's 2002 Audit of the Optimization Agreement, Berkshire has shown that the audit was performed by qualified personnel with training and expertise in internal auditing (Exhs. AG 3-1, Att. A at B-1 (confidential), AG 3-2 (confidential)). There is no basis on which to conclude that the use of internal Energy East personnel influenced the outcome of the Audit. Therefore, we will not require the Company to conduct an additional internal audit of all BP transactions under the 2001 and 2002 agreements. The Company indicated that an external auditor will conduct an evaluation of Berkshire's finances, including a review of the savings under the Optimization

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Agreement (Tr. at 83-84). While we will not require an additional external audit at this time, we direct the Company to provide the Department with a copy of the external auditor's evaluation as soon as it is available. In addition, Berkshire must continue to provide the Department with Energy East's annual audits of the Optimization Agreement.

Regarding the Attorney General's concerns about BP's reporting procedures, we find that Berkshire and BP must continue to work together to streamline and improve BP's back office systems. The Company is directed to keep detailed documentation of all transactions under the Optimization Agreement and submit an annual report to the Department containing a summary of all transactions on behalf of the Company. In addition, the annual reports should describe any proposed substantive changes to ***486** the Optimization Agreement, including refinements to the allocation method, the Company's participation share, pricing provisions, and changes to the aggregate minimum savings. The annual reports should also include the dollar amount of savings accrued to the Company with an explanation of how such savings were generated and allocated between the Alliance LDCs. Finally, the annual reports should highlight any problems that arose during the implementation of the Optimization Agreement, including any issues with BP's back office systems and reporting procedures, and discuss the steps that the Company and BP have taken to address these problems. Berkshire must submit such annual reports no later than April 1st of each year.

C. Margin Sharing

[8-11] The Department has acknowledged that the regulatory policy of requiring all margins derived from capacity-management tools (i.e., interruptible sales, capacity release, interruptible transportation, and off-system sales) to flow to firm customers can result in a disincentive for LDCs to make investments that are in the public interest. D.P.U. 93-141-A at 59. Similarly, the Department has recognized that when giving utilities financial incentives to improve efficiency and a greater share of the resulting cost savings, real benefits to customers can be achieved. Id., citing Incentive Regulation, D.P.U. 94-158, at 47-52 (1995). The Department has stated that the ability of LDCs to take advantage of market opportunities allows them to generate additional margins that could reduce the average cost of service to firm customers. D.P.U. 93-141-A at 59-60. Consequently, LDCs are allowed to retain 25 **percent** of annual incremental margins earned from interruptible sales, interruptible transportation, **off-system sales**, and **capacity release**. D.P.U. 93-141-A at 64. More recently, the Department has found that LDCs should not be penalized with the loss of capacity-mitigation revenues as a result of pursuing a portfolio-management approach that will produce benefits for customers. Boston Gas Company, Colonial Gas Company, and Essex Gas Company, D.T.E. 99-76, at 22. [FN15]

As an initial matter, the Attorney General argues that, because the goal of the Optimization Agreement is to reduce costs, the Company's proposal is ineligible

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for margin sharing (Attorney General Brief at 11). [FN16] However, we find that the Attorney General has mis-characterized the Company's proposal and the Optimization Agreement. Berkshire has not submitted a proposal to mitigate price volatility. Rather, the Optimization Agreement has been structured with the ultimate goal of reducing costs to the Company's firm customers. Under the Optimization Agreement, the Company will use financial instruments to reduce commodity costs and strategies to mitigate capacity. Therefore, we find that, similar to the agreement approved by the Department in D.T.E. 99-76, the transactions under the Optimization Agreement are eligible for margin sharing.

With respect to the structure of Berkshire's margin sharing proposal, the arrangement is consistent with the criteria set forth in D.P.U. 93-141-A. Specifically, the Company's proposal complies with the Department's directives with regard to the allocation of margins, the applicable threshold level, as well as the percentage of margins to be retained by Berkshire. Failure to approve Berkshire's proposed treatment of margins would eliminate all incentives by the Company to seek arrangements such as the current portfolio optimization structure and penalize Berkshire for pursuing such activities with loss of capacity-mitigation revenues, which the Company could earn absent this Optimization Agreement.

Therefore, because Berkshire's portfolio optimization activities under the Optimization Agreement are designed to reduce costs to ratepayers and the margin sharing arrangement is consistent with the criteria set forth in D.P.U. 93-141-A, Berkshire's margin sharing proposal is approved. In flowing back the margins via the GAF and the local distribution adjustment factor filings, we direct the Company to track and record each transaction margin in a manner consistent with D.P.U. 93-141-A.

The Attorney General contends that any margin sharing by the Company should be subject to certain conditions. First, the Attorney *487 General argues that the Department should allow the Company to earn incentives only when the Company's activities can be shown to offer proven benefits (Attorney General Brief at 12-13). However, by the terms of its proposal, Berkshire will earn margins only if savings (and, therefore, ratepayer benefits) are generated in excess of the savings from the same activities in the previous year.

Second, the Attorney General argues that the Company should be required to have an independent assessment performed to ensure reporting accuracy before any margin sharing is allowed (Attorney General Brief at 14). However, Berkshire indicated that an external auditor will be evaluating savings under the Optimization Agreement and will submit the resultant data to the Department (Tr. at 83-85). Therefore, as we stated in Section V.B. above, we will not require an independent external audit at this time.

D. Legal Bills

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[12, 13] The amount of gas acquisition, planning, and dispatching costs ('gas acquisition costs') that a company may recover is determined in the company's rate case. See *Boston Gas Company*, D.P.U. 93-60, at 281 (1993). This amount is then recovered via the company's GAF. Gas acquisition cost is a fixed amount that is recovered annually until the company's next rate case. *Id.* at 282. In other words, in between rate cases, a company's gas acquisition cost cannot be changed from the amount determined in its last base rate proceeding. [FN17]

In context of the Department's review of the 2002 Optimization Agreement approved in D.T.E. 02-19, the Company did not propose to recover legal fees through its GAF for services rendered in connection with gas portfolio and optimization activities. As a result, the Department did not approve the collection of legal fees for such activities.

In the instant proceeding, Berkshire argues that its recovery of \$118,000 in legal fees through the GAF is appropriate because such fees are associated with its efforts to procure gas supply (Company Brief at 21). The legal fees incurred by the Company for its portfolio optimization activities are gas-supply related and, therefore, constitute gas acquisition costs. However, as we stated above, the amount of gas acquisition costs that a company may recover is fixed and does not change until the company's next rate case filing. In the Company's last rate case, although Berkshire had an asset management plan in place, the Company did not propose to include legal fees associated with gas optimization activities as an adjustment to its test year amount of gas acquisition costs. The Company cannot now seek recovery of these costs outside of the amount determined in its last rate case.

Therefore, because Berkshire's gas acquisition costs were determined in the Company's last base rate proceeding, the Department finds that the Company has inappropriately collected \$118,000 in gas acquisition costs via its GAF. Accordingly, in Berkshire's next GAF filing, we direct the Company to refund, with interest, any legal fees associated with gas optimization activities that it has already collected via its GAF. Similarly, Berkshire may not collect legal fees for services rendered in connection with the instant proceeding in the Company's next GAF filing.

E. Purchase Agreement

[14] The Department's review of the proposed Purchase Agreement indicates that it is consistent with Berkshire's resource portfolio objectives presented in the Company's most recent forecast and requirements plan approved by the Department in D.T.E. 02-17. As we found above, BP's resources compare favorably to the range of alternatives reasonably available to the Company and its customers. Further, unlike the Company's 2002 Purchase Agreement, Berkshire is no longer limited to procuring Gulf Coast gas supplies from BP (Exh. BG-3, \$2.7). [FN18] Accordingly, the Department finds that the Purchase Agreement is consistent with the public in-

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terest and is approved.

VI. ORDER

*488 Accordingly, after due notice, hearing, and consideration, it is

ORDERED: That the Optimization Agreement and Purchase Agreement between The Berkshire Gas Company and BP Energy Company are APPROVED; and it is

FURTHER ORDERED: That The Berkshire Gas Company shall comply with all other directives contained in this Order.

FOOTNOTES

FN1 Berkshire is a wholly-owned subsidiary of Energy East Corporation (Exh. BG-2, at 3).

FN2 The supplemental briefs were limited to issues concerning the Company's audit of the savings produced as a result of the 2002 Optimization Agreement ('2002 Audit'). The 2002 Audit was produced in a supplemental response to Exh. DTE 1-25. Because the 2002 Audit was not available until after the September 9, 2004, evidentiary hearing, the Department permitted the Attorney General to issue an additional round of discovery (Tr. at 3-7). On our own motion, the Department moves the Company's responses to Information Requests AG 3-1 through AG 3-13 into the evidentiary record.

FN3 The four LDCs are Connecticut Natural Gas Corporation, The Southern Connecticut Gas Company, New York State Electric and Gas Corporation, and Rochester Gas and Electric Corporation (Exh. BG-2, at 3). Maine Natural Gas Company, a smaller affiliated company, also receives some supply-related services from BP but does not directly participate in optimization activities (id.).

FN4 The 2001 Optimization Agreement was for a one-year period. D.T.E. 01-41. The 2002 Optimization Agreement was for a two-year period. D.T.E. 02-19.

FN5 Least-cost routing will be determined using production area indices, pre-existing contract prices, and actual pipeline variable costs (Exh. BG-4, § 12.1).

FN6 The Company executed several ancillary agreements in connection with the Alliance, including an allocation agreement that describes the allocation of savings generated under the Optimization Agreement among the Company and the other members of the Alliance (see Exh. BG-3, exh. B-10 (confidential)). The Company also executed a netting agreement that memorializes certain payment or settlement procedures (see Exh. BG-3, exh. B-9 (confidential)).

FN7 According to the Attorney General, the Department permits the use of derivatives for hedging, but not for speculative purposes (Attorney General Brief at 5, n.5, citing D.T.E. 01-41, at 14).

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FN8 The Attorney General states that, in D.T.E. 02-19, the Department required Berkshire to submit annual reports within 60 days of the end of every contract year that: (1) contain detailed documentation of all BP portfolio optimization transactions; (2) detail any refinements made to the allocation method; (3) list the savings dollars accrued to the Company; (4) describe how savings were generated and allocated between the LDCs in the Alliance; (5) summarize BP's transactions on behalf of the Company; (6) highlight problems that arose during implementation of the 2002 Optimization Agreement and related agreements; and (7) describe how the Company and BP dealt with any implementation problems (Attorney General Brief at 4, n.4, citing D.T.E. 02-19, at 19)). The Attorney General states that Berkshire filed its 2003 report within the required 60-day period but the Company's 2004 report was one week late (Attorney General Brief at 4, n.4, citing Exhs. AG 1-4, AG 1-31).

FN9 According to the Attorney General, Berkshire has agreed to submit all amendments, supplements, or substantive changes to the Optimization Agreement to the Department for approval (Attorney General Brief at 8, n.17, citing Exhs. DTE 1-35, 1-36; Tr. at 79, 145, 172). The Attorney General contends that the definition of 'substantive changes' should include changes that directly or indirectly increase Berkshire's cost of gas adjustment ('CGA') costs, including, but not limited to, changes (1) the Company's participating share; (2) the allocation procedures; (3) any pricing term, including the aggregate minimum savings; and (4) the resources available to the Alliance (Attorney General Brief at 8, n.17).

FN10 The 'back office system' refers to the administrative capability to handle the data, communication, billing, reporting a tracking required under the Optimization Agreement.

FN11 The Department notes that Berkshire achieved savings under the previous agreements (Exh. BG-1, at 5; Company's June 17, 2003 Annual Report; Company's August 5, 2004 Annual Report; Tr. at 22). The savings were returned to the Company's ratepayers through the GAF (Exh. AG 1-48).

FN12 For example, dramatically cold weather offers limited opportunity for LDCs to seek optimization savings because of the need to retain their supply resources to ensure service reliability.

FN13 Rochester Gas and Electric Corporation did not participate in the 2002 Optimization Agreement (Exh. BG-2, at 3).

FN14 The Department's objective is not to dictate a precise plan for resource or capacity acquisition but, rather, to ensure that the manner in which a company proposes to acquire resources and capacity is consistent with the public interest. By demonstrating that the Company's ratepayers will likely benefit from the Alliance arrangements under the most unfavorable optimization conditions, we find that the Alliance arrangement contributes to an overall least cost resource plan and,

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thus, is consistent with the public interest. See D.T.E. 02-19, at 16, n.13

FN15 In D.T.E. 99-76, at 6-7, the Department approved a contract whereby an independent portfolio manager would assume the right to manage the three LDCs' combined portfolios in exchange for a management fee payable to the LDCs. Id. at 6-7. The Department also approved the LDCs' proposal to retain 25 percent of revenues received under the portfolio agreement. Id. at 23.

FN16 The Department has rejected incentive mechanisms in conjunction with LDCs' riskmitigation programs, finding that they (1) would not be consistent with the Department's goal of promoting market-based regulation and enhanced competition in that it would not serve as a vehicle to a more competitive environment; and (2) could negatively affect the development of retail competition and customer choice in Massachusetts. D.T.E. 01-100-A at 24, citing Incentive Regulation at 59. The Department stated that incentive mechanisms would be more appropriately associated with programs whose objective is to lower costs or increase service quality, rather than with financial hedging programs whose objective is to mitigate price volatility. Id. at 22.

FN17 The Company's witness stated that Berkshire was familiar with the Department's precedent concerning the recovery of gas acquisition costs, namely that 'the costs of gas acquisition are set in a company's rate case at a set amount, and they are recovered pursuant to the CGA' (Tr. at 63-64).

FN18 The Department has stated that a company should not limit the purchase of its gas supply requirements to one supplier. D.T.E. 01-41, at 12, citing Commonwealth Gas Company, D.P.U. 94-174-A (1996).

*489 EDITOR'S APPENDIX

PUR Citations in Text

MASS.] Re Incentive Regulation for Electric and Gas Co., 159 PUR4th 585, D.P.U. 94-158, Feb. 24, 1995.

MASS.] Re Interruptible Transportation Offered by Local Distribution Co., 171 PUR4th 287, D.P.U. 93-141-A, Feb. 14, 1996.

MASS.] Re Risk Management Techniques to Mitigate Natural Gas Price Volatility, 221 PUR4th 391, D.T.E. 01-100-A, Oct. 9, 2002.

END OF DOCUMENT

Westlaw.

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Re Baltimore Gas and Electric Company
Case No. 8500(y)
Order No. 78622

Maryland Public Service Commission
August 14, 2003

ORDER rejecting a hearing examiner's proposed order and authorizing a natural gas local distribution company to recover the whole of its claimed purchased gas costs. Of the \$9.4 million in costs that the company had sought to recoup, the hearing examiner had approved only \$1.5 million, explaining that a computational error had led the company to double-credit certain capacity release payments, which could not be recovered under the terms of the company's gas service tariff. However, the commission finds the gas service tariff not to be dispositive. Instead, the commission finds that the transactions were governed by Federal Energy Regulatory Commission (FERC) regulations. Commission holds that included in the multiple capacity release payments made by the company were FERC-regulated pipeline transportation and storage charges, which the commission has always allowed to be recovered from customers on a dollar-for-dollar basis. Accordingly, the commission permits the company to recoup the entirety of its \$9.4 million claim over a two-year period.

P.U.R. Headnote and Classification

1.

AUTOMATIC ADJUSTMENT CLAUSES

s10

Md.P.S.C. 2003

[MD.] Direct energy costs -- Purchased gas and commodity costs -- Associated capacity release payments -- Recovery from customers despite computational and double-crediting errors -- Factors -- Payments as including federally regulated pipeline transportation and storage charges -- Filed rate doctrine -- Traditional passthrough on dollar-for-dollar basis -- No justification for nonrecovery -- Local gas distribution company.

Re Baltimore Gas and Electric Company

P.U.R. Headnote and Classification

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EXPENSES

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Md.P.S.C. 2003

[MD.] Gas utility -- Commodity or supply costs -- Associated capacity release payments -- Recovery from customers despite computational and double-crediting errors -- Factors -- Payments as including federally regulated pipeline transportation and storage charges -- Filed rate doctrine -- Traditional passthrough on dollar-for-dollar basis -- No justification for nonrecovery -- Local gas distribution company.

Re Baltimore Gas and Electric Company

BY THE COMMISSION:

This matter is before the Commission on appeal of a Proposed Order issued December 18, 2002.

I. PROCEDURAL HISTORY

On January 18, 2002, the Baltimore Gas and Electric Company ('BGE') was instructed by the Director of the Commission's Accounting Division to discontinue the recovery of \$9.4 million through the Annual Capacity Release Adjustment factor of BGE's MBR rates pending a review and determination. The matter was scheduled for consideration by the Commission at its Administrative Meeting of March 13, 2002 and, on April 5, 2002, was delegated to the Commission's Hearing Examiner Division. Testimony was filed in the spring and early summer of 2002 and a hearing was held on July 12, 2002. All briefs were on file by August 23, 2002.

The Proposed Order recommended that the Commission permit BGE to recover that portion of the pipeline reservation costs attributable to an error in computing the Annual Capacity Release Adjustment as applied in the accounting period for the year 2001. Under the Proposed Order BGE would recover approximately \$1.5 million and BGE would be disallowed recovery of approximately \$7.9 million.

On January 17, 2003, BGE filed its Notice of Appeal, followed on January 27, 2003 by its Memorandum on Appeal. The Commission's staff ('Staff') and the Maryland Office of People's Counsel ('OPC') filed their respective Reply Memorandums on February 19, 2003. [FN1]

II. THE FACTS

The facts are not in dispute and will be briefly recounted. In January 2002 BGE made its monthly MBR submittal to the Accounting Division. In it BGE proposed an adjustment to the MBR rate that would have resulted in the recovery by BGE, over a

period of two years ending in approximately December 2003, of \$9.4 million. This amount represented the customer's portion of the proceeds for Capacity Release transactions conducted by BGE but mistakenly credited twice to the customers during the period January 1999 through October 2001. In other words, the customers were entitled to receive \$9.4 million but actually received \$18.8 million over that period of approximately two years and ten months.

Capacity Release transactions allow holders of firm interstate pipeline and storage capacity contracts to make such capacity available to third parties for relatively short periods of time for a fee. The underlying contracts, as well as the capacity release market, are subject to regulation by the Federal Energy Regulatory Commission ('FERC'). BGE, as one holder of such long-term contracts, can mitigate, through Capacity Release transactions, the costs of those contracts that are otherwise recovered on a dollar-for-dollar basis from its gas customers. As a result of a plan previously approved by this Commission, BGE credits 90 percent of the proceeds for the **Capacity Release** transactions to its gas customers through the MBR mechanism and, to the extent of the crediting, lowers the costs that these customers would otherwise bear. The original MBR mechanism was, however, complex and subject to computation errors. [FN2] Over the period since 1996, when the Commission approved the MBR mechanism, there were 13 adjustments authorized for errors in computation of the MBR rates. On six of these occasions BGE was authorized to recover under-collections. On seven occasions it was authorized to refund over-collections.

III. THE PROPOSED ORDER

The Proposed Order attributed the amount in dispute to an error in computing the Annual Capacity Reservation Adjustment and viewed the dollars at issue as an under-recovery of firm transportation and storage costs. The Proposed Order did not specifically rule on the arguments posed by Staff and OPC relating to COMAR 20.55.04.05(E) but did note that BGE's opposition to these arguments appeared to have merit. Rather, the Proposed Order concluded that whether the dollars associated with the mistake in the calculation of the Capacity Reservation Adjustment should be recouped is resolved by the terms of BGE's Gas Service Tariff, guided by the Commission's decision in Baltimore Thermal Energy Corporation, 80 Md. PSC 305 (1989).

IV. BGE'S ARGUMENTS ON APPEAL

BGE challenges the Proposed Order initially on its conclusion regarding the characterization or nature of the \$9.4 million, arguing that it was, in fact, an over- or double payment of proceeds from Capacity Release transactions. BGE also challenges the decisional rationale of the Proposed Order. BGE argues that the Examiner's strict reading of the Gas Service Tariff to support a partial disallowance is unsupported by prior practice or precedent. In support, BGE offers the prior period adjustments approved in past proceedings involving both BGE and Columbia

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Gas of Maryland. Among others, BGE specifically cites Case No. 8511(z) in which the Commission allowed Columbia Gas of Maryland ('Columbia ') to correct a prior double credit error that spanned two prior review periods and Staff testimony filed in July 2002, again covering Columbia, that accepted a \$9 million prior period adjustment.

BGE also argues that the Baltimore Thermal decision was read too narrowly by the Examiner and that the decision does not stand for a blanket prohibition on prior period adjustments. Finally, BGE observes that FERC, having dealt with prior period adjustments and received guidance from the courts, has developed a four-prong test in order to prevent situations where a disallowance would operate as a penalty.

V. STAFF'S AND OPC'S ARGUMENTS IN REPLY

Both Staff and OPC argue in their respective Reply Memorandums that the Proposed Order is supported by record evidence, [FN3] Commission precedent or PUC law and that it should be adopted by the Commission.

Notwithstanding its support of the Proposed Order, Staff returns, as its first supportive argument, to its theory during the hearing stage. Staff argues that COMAR 20.55.04.05(E) should govern the issue in this case and, as a result, BGE's recovery should be limited to a fraction of the \$9.4 million. Second, Staff argues that the 'Examiner did not err as a matter of law by applying the legal analysis in Baltimore Thermal.' Staff also replies to BGE to the extent it attempts to distinguish Case No. 8511(z) on the basis that the costs for which the prior period adjustment was allowed should have been allocated to a non-Maryland affiliate and that a second prior period adjustment was the product of a settlement supported by Staff. [FN4] Finally, Staff argues that the Proposed Order reached the right outcome because BGE must be held accountable for its errors.

The Examiner's characterization of the \$9.4 million as an under-recovery is supported by OPC. OPC argues that, because BGE improperly applied its Tariff, BGE under-recovered pipeline capacity costs. OPC concedes that the Commission has the authority to allow prior period adjustments, but argues that they should be the exception, not the rule. In this instance OPC asserts that the prior period adjustment should not be allowed because the 'ratepayers from whom BGE now seeks to recover the \$9.4 million may not have been customers when the mistakes were made'

OPC also supports the Examiner's application of Baltimore Thermal and his conclusion that BGE's Annual Capacity Reservation Adjustment provision of its Gas Service Tariff 'is the mechanism that allows for recoupment of any over- or under-recovery of revenues related to pipeline transportation and capacity costs.' As such, according to OPC, BGE is limited to that fraction of the \$9.4 million attributable to the 12-month limitation period in the Tariff. The Examiner's de-

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cision is, according to OPC, bolstered by the principles and policy reasons discussed in Baltimore Thermal.

Finally, OPC argues that BGE's reliance on old Section 54F electric fuel rate cases as support for a prior period adjustment in this case is fatally flawed because the MBR mechanism itself is defective.

VI. COMMISSION DISCUSSION AND DECISION

[1, 2] The \$9.4 million is at issue here because BGE erroneously credited it twice to its gas sales customers. The various efforts to characterize the \$9.4 million otherwise are not helpful to an analysis, indeed in some cases obfuscate an analysis of the issue, and are rejected.

Equally clear to the Commission is the nature of the \$9.4 million. These are proceeds from multiple Capacity Release transactions engaged in by BGE involving assets subject to the regulatory authority of FERC. The rates paid by BGE for these pipeline transportation and storage assets are regulated by FERC. The Commission has recognized for many years that the costs of transportation and storage of natural gas are included within the meaning of 'purchased gas costs.'

FERC also sets and oversees the rules governing the Capacity Release market. Because the underlying assets used in the Capacity Release transactions are held for the benefit of the firm gas sales customers, the Commission has required, since shortly after **Capacity Release** transactions began, that the companies credit a certain portion of the proceeds -- varying from 80 **percent** to 90 **percent** -- from the **Capacity Release** transactions to the firm sales customers. Thus, the costs that the customers bear for the capacity are mitigated to the extent of the proceeds. As a consequence of being incorporated into this calculation, the proceeds of the Capacity Release transactions are treated as gas costs.

In 1991, in a decision concerning the treatment of gas costs similar to those at issue here, the Court of Special Appeals concluded that 'the Supreme Court had made clear that, under the Federal supremacy and preemption doctrines, the States may not bar regulated utilities from passing through to retail customers FERCmandated wholesale rates.' [FN5] The Court continued, quoting the Supreme Court's explanation of the 'filed rate doctrine' as follows:

The filed rate doctrine ensures that sellers of wholesale power governed by FERC can recover the costs incurred by their payment of just and reasonable FERC-set rates. When FERC sets a rate between a seller of power and a wholesaler-as-buyer a State may not exercise its undoubted jurisdiction over retail sales to prevent the wholesaler-as-seller from recovering the costs of paying the FERC-approved rate Such a 'trapping' of costs is prohibited. [FN6]

The regulatory treatment in Maryland of the interstate transportation and storage costs is governed in large part by Sections 4-402, 4-202 and 4-203 of the Public

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Utility Companies Article. The core components of these statutes have been a part of public utility law in Maryland for many years and are applied in the context of the preemption and filed rate doctrines. Section 4-402 authorizes the Commission to disallow recovery of purchased gas costs to the extent the company fails to show that charges were based on the costs, that its procurement and purchasing practices were reasonable or that it did not follow competitive practices in procuring and purchasing the gas.

Section 4-202 requires a public service company, such as BGE, to file with the Commission a tariff schedule of its rates and charges for regulated services, such as the MBR gas sales service. Section 4-203 prohibits a public service company from charging a rate for regulated services other than that contained in the tariff.

The \$9.4 million, as proceeds from Capacity Release transactions utilizing FERC-regulated transportation and storage assets, qualify for dollar-for-dollar recovery pursuant to the filed rate doctrine. Moreover, in recognizing the capacity release program the Commission's intent has been to ensure that customers receive the prescribed amount of every dollar of proceeds recouped by the Company, neither more nor less. Further, implicit in the arguments of the parties advocating a disallowance is the admission that the costs at issue do reflect the costs actually incurred by BGE. The evidentiary record does not contain any reasonable basis for the Commission to conclude that BGE has somehow imprudently incurred these costs. Consequently, the Commission concludes that BGE is entitled to recover the entire \$9.4 million from its gas customers.

In addition, Sections 4-202 and 4-203 operate as a separate reason for BGE to fully recover the \$9.4 million. BGE is required to charge the rates contained in its Gas Service Tariff for the regulated MBR retail gas sales service. The fact that BGE made a mistake in calculating the rate pursuant to the method prescribed in the Tariff and underlying settlement does not excuse BGE from this obligation. The double-refunding of Capacity Release proceeds to customers is inconsistent with the Company's tariff and is unlawful under §§ 4-202 and 4-203. Moreover, the double-refunding of these proceeds is inconsistent with the purpose of the Capacity Release program as approved by the Commission for implementation on BGE's system.

The parties advanced four theories for partial disallowance of the \$9.4 million. They are, in no particular order, based upon an interpretation of COMAR 20.55.04.05(E), a reading of the decision in Baltimore Thermal, an intergenerational transfer argument and an interpretation of the Annual Capacity Reservation Adjustment ('ACRA') clause in BGE's Gas Service Tariff.

A review of the history and purpose of Chapter 4, of which subsection 20.55.04.05(E) is a part, shows that this Chapter is focused on the fundamentals of rendering gas service. These fundamentals are metering and meter integrity, gas

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quality, safety, conditions for service, bill format, record keeping, customer information and bill adjustment. Subsection .05(E) of Chapter 4 is relied upon in support of a partial disallowance argument insofar as .05(E) limits the past period used to calculate bill adjustments to 12 months for undercharges or up to three years upon prior authorization from the Commission. Since no authorization was obtained, according to this interpretation, the past period to be used to calculate the undercharge is limited to 12 months. That calculation produces an amount, to be collected through a bill adjustment, of approximately \$1.7 million.

This interpretation of subsection .05(E), while accompanied by argument, is not supported by any citation to a previous decision by this Commission. On the other hand, a review of the long history of Chapter 4 shows that a correct reading of subsection .05(E) does not support its use as authority for a partial disallowance in this case and therefore that interpretation is rejected.

Chapter 4 was initially promulgated in 1915. [FN7] It did not contain a bill adjustment provision nor did a revision in 1936. [FN8] The 1954 revision included the concept of using the bill as a means for correcting billing mistakes arising from fast and slow meters. [FN9] It was included in, and relied upon the other provisions of, subsection 4.07 that also addressed Fast Meters, Slow Meters and Non-registering Meters. The final part of that subsection -- Billing Error -- provided a means for remedying the problems addressed in the preceding three sections as well as the incorrect application of a rate schedule. [FN10] This fundamental connection to metering errors continued through subsequent major revisions and into today's Chapter 4. The next revision, in 1964, altered the length of the past periods which could be used to calculate billing adjustments arising out of fast and slow meters. [FN11] The last major revision, in 1974, preceded by 17 years the Court of Special Appeals' opinion in GMC and by approximately 13 years the opinions of the Supreme Court in Nantahala and Mississippi Power. It did not, however, precede, either in time or in weight of authority, the Federal supremacy and preemption doctrines, nor the standards and requirements currently contained in Section 4-402, nor the requirements of Sections 4- 202 and 203. Read in the manner proposed by Staff, the regulation would produce a result that is contrary to the requirements of those doctrines and statutes and so it must give way.

Setting aside for a moment its clear purpose as a remedy for metering errors, the regulation should be read, if possible, so as to allow it to fit within the requirements of superior legal authority. In proper recognition of the relative ranking of a regulation vis--vis a statute, for instance, each promulgation of the regulations just cited included language similar to that found in subsection 1.2.5 of the 1974 revision:

These regulations shall in no way relieve any utility from any of its duties under the laws of this State.

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Subsection .05(E) was originally intended and continues to be a means to remedy defective meters and associated reasons for misbilling such as the application of a rate schedule applicable to a different customer class than the one to which the customer being billed belongs. For that reason and because the regulation cannot trump the filed rate doctrine and the statutory requirements cited, subsection .05(E) does not operate to limit BGE's recovery of the \$9.4 million in this case and that theory is rejected.

The decision in Baltimore Thermal cannot support the weight that it is being asked to bear. First, the underlying recommendation is that of a Hearing Examiner who, in the proposed order states 'I am not prepared to set precedent on all of the issues without the benefit of an adversary's analysis.' [FN12] The Proposed Order became an Order of the Commission after no appeal was filed and by operation of law.

Second, the disallowance in Baltimore Thermal did not run counter to the filed rate doctrine and that company's right to dollar-for-dollar cost recovery.

Third, the underlying error in that case was a failure to include an item, that would otherwise have qualified, in those costs that together comprised the basis for setting a fuel rate. In this case, the underlying error was a failure to charge the rate set in the Tariff by dint of a double credit. In Baltimore Thermal the mistake did not violate Sections 4-202 and 203. In this case it did.

Therefore, reliance on Baltimore Thermal as the basis for a partial disallowance in this case is rejected.

The period over which gas sales customers were erroneously credited with \$9.4 million spanned January 1999 through October 2001. Under this Order BGE is going to be authorized to collect this amount but the third theory for disallowance argues that the intergenerational transfer thus authorized will be inequitable. Accepting for discussion purposes the numbers in Staff's testimony, approximately 15,000 customers of 520,000 left BGE's gas sales service during the period January 1999 through October 2001. That is approximately three percent.

This indicates that the rate of migration from delivery service to sales service and back on BGE's system is low. This stability is confirmed by other publicly available data. Ratemaking decisions, including decisions on prior period adjustments, are necessarily made in terms of classes of customers. They cannot be made, except in exceptional circumstances, with a focus on an individual customer. Therefore, some transfers among individual customers belonging to different groups or over time is unavoidable. The question is whether the transfer is such as to produce a rate that is thereby made unjust and unreasonable in violation of Sections 4-201 and 4-101 of the Public Utility Companies Article.

The MBR mechanism is subject to a number of adjustments and mitigation measures that operate to transfer costs from the period in which they are incurred to a

later period for collection. These or similar factors have been a part of the MBR mechanism since the Commission originally accepted it and were not seen as inequitable transfers at that time. There is no indication that that determination should be changed. Moreover, any concerns that may arise will be mitigated by the extended period over which the amount will be collected. For these reasons, the Commission does not consider the intergenerational transfer effected by the collection of the \$9.4 million to be sufficient to be inequitable in this case and the resulting collection rates will be just and reasonable. [FN13]

Therefore, an inequitable intergenerational transfer is rejected as the basis for a partial disallowance.

The fourth theory for a partial disallowance is based on a portion of BGE's Gas Service Tariff. The provision relied upon, the Annual Capacity Reservation Adjustment ('ACRA'), is used as the basis for limiting the recovery calculation to a 12-month period. This is a misreading and misapplication of the ACRA. BGE's double refund resulted from a failure to correctly follow the ACRA provision of the Tariff. Section 4-203, however, prohibits BGE from charging other than in accordance with its Tariff, including the ACRA. To the extent it does, that action must be remedied. The ACRA is not correctly read as a bar to recovery, it sets the rule under which recovery occurs.

This reading and application conforms the ACRA with the requirements of the filed rate doctrine and with previous Commission practice. Therefore, the theory relying on the ACRA as a partial bar to recovery of the \$9.4 million is, under the facts of this case, rejected.

Requests for prior period adjustments, while not to be encouraged, will remain a fact of regulatory life as long as mechanisms such as purchased gas clauses exist. The regulatory issue is how to deal with these requests. While the Commission will not apply it in this case, the Commission notes that FERC has litigation history involving treatment of prior period adjustments, including guidance from the courts. FERC's experience may be instructive for other types of prior period adjustment cases that may arise before this Commission in the future. [FN14] Based on that experience and guidance FERC articulated a four-part test analysis to help guide its decisions in such matters. FERC asks the four following questions:

1. Whether the company would receive a windfall as a result of its action;
2. Whether the company's customers would receive a windfall if the Commission refused to allow the passthrough of costs;
3. How the Commission acted when faced with similar issues; and
4. Whether an alternative remedy to outright denial of the recovery of the costs would be more proportional to the error committed by the company.

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While there are differences in the law governing FERC and this Commission, there are similarities in the fact patterns of cases involving prior period adjustments and the Federal experience may prove helpful. Therefore, in the next case in which Staff participates involving the use of a prior period adjustment, Staff is directed, in addition to any other position it decides to take or theories it decides to advance, to file testimony applying and to brief the four-part test developed by FERC to determine if cost recovery as a prior period adjustment should be granted.

In light of the above discussion and decision, the matter of how the \$9.4 million should be recovered remains. BGE proposed a recovery period of two years when it made its filing that precipitated this case. That filing was made approximately 18 months ago and, if accepted at the time, would have resulted in completion of the collection this December. The period over which the error was made was approximately two years and ten months. While a term of approximately the same length is generally appropriate over which to spread the recovery, such a period in this case is unfair to BGE given the 18 months that have already passed. Deducting the 18 months from that period, however, would mean a recovery period of about 16 months, which will work a disproportionate recovery on the non-heating load customers.

The Commission accepts BGE's original proposal for a two-year recovery period to commence this September or as soon thereafter as possible. That will encompass two winter periods, two non-heating load periods and produce a charge on customer bills that will not create an undue burden on the customers or an inequitable intergenerational transfer. A recovery spanning two winters and two summers will also mitigate any interseasonal transfers between the heating and non-heating customers.

IT IS, THEREFORE, this 14th day of August, in the year Two Thousand Three, by the Public Service Commission of Maryland,

ORDERED: (1) That Baltimore Gas and Electric Company is directed to collect, over a two-year period, the unrecovered balance of the \$9.4 million that was double-credited to customers commencing with the September billing cycle or as soon thereafter as possible.

(2) That the theories under which recovery of the \$9.4 million would be disallowed, whether in whole or in part, are rejected.

(3) That the Commission's Staff is directed to incorporate into its analysis and case, at such time as the next proceeding involving a prior period adjustment in which it participates, the four-part test as discussed herein.

Kenneth D. Schisler
J. Joseph Curran, III
Gail C. McDonald

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Ronald A. Guns
 Harold D. Williams

ADMISSION OF SERVICE

_____(date)
 I/We

'11P'

'14.5P'

'14.5P' hereby admit service on this date of one copy(s) of the Proposed Order of Hearing Examiner issued in Case No. 8500(y), dated August 14, 2003, in the matter of _____

'14.5P'

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'14.5P'

(sign here) _____

PROPOSED ORDER OF HEARING EXAMINER

This matter is before the Commission to resolve the question of whether Baltimore Gas and Electric Company ('BGE' or 'the Company') can effect recovery of what is characterized as an 'over-refund' of Capacity Release Credit provided its firm sales customers in several accounting periods prior to the Company's 2002 Market-Based Rate filing. For the reasons discussed below, it is decided that BGE can recover the 'under-recovery' of pipeline reservation costs attributable to an error in computing the Annual Capacity Release Adjustment as applied in the accounting period for the year 2001.

I.

In 1996, the Commission approved the establishment of a Market-Based Rates ('MBR') program to be used to set gas prices for BGE customers. See, Re Baltimore Gas and Electric Company, 87 Md. PSC 183 (1996). The program approved by the Commission was the product of a settlement agreement reached by the Company, the Commission Staff ('Staff') and the Office of People's Counsel ('OPC'). The MBR program was to replace the Purchased Gas and Commodity Charge Adjustment ('PGA/CCA') mechanism previously used to set gas prices for BGE customers. The program established a new method for calculating 'the cost of gas obtained for firm customers, ...procedures for sharing between BGE and its customers the difference (positive or negative) between the market price and certain adjusted City Gate [FN1] benchmark indices, and ...define[d] the nature of Commission review' for implementation

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of the program. Id. at 184. As part of the computation of the MBR, revenues received by the Company for the sale or release of its excess pipeline capacity of gas is shared between BGE and its customers, with BGE receiving 10 percent and its customers 90 percent of these revenues. Application of the receipt of these revenues is reflected in a calculation that results in a credit adjustment applied as a component of the commodity gas price. It is an error by the Company in applying its tariff to the adjustment reflected in the gas price that is the basis for this dispute. [FN2]

Section 4-402 of the Public Utility Companies Article requires the Commission to conduct, at least annually, an evidentiary hearing to review any changes in the commodity cost of gas that BGE passes directly on to its customers. Between the periods of review, the Company submits monthly filings of the MBR rate to the Commission Staff. The rate takes effect subject to limited administrative review by the Staff. At the annual review, adjustments to be made to any of the filings of the preceding 12 months are subject to full evidentiary review.

BGE, in its January 2002 monthly MBR filing, proposed an adjustment to obtain recovery of \$9.4 million for the over-refund of Capacity Release Credits to its customers from January 1999 through October 2001. The Company proposes to recover the over-refund over a two-year period estimating 'that the typical residential heating customer would pay an additional 56 cents per month on average.' BGE Brief, p. 5. The over-refund of Capacity Release Credits was the consequence of an error described as 'inadvertent' (Direct Testimony, BGE Witness John L. Hays, pg. 11.) borne of 'the great complexity of the original MBR mechanism ... and as a result was not discovered in a more timely manner.' The process that gave rise to the over-refund is described as follows:

Under ...the Company Gas Service Tariff in effect during the period of the over-refund, customers were entitled to a 90% share of pipeline reservation credits resulting from BGE's participation in the interstate pipeline capacity release program. The Company implemented this provision by appropriately crediting customers for their 90% capacity release credits ...of each monthly commodity rate filing.

Also ...the Company performs an annual reconciliation of the actual cost of pipeline transportation and storage capacity and the revenues collected over the year pertaining to capacity costs. Any difference between the actual cost and the revenues collected is to be applied to rates over a subsequent twelve-month period. During the annual reconciliations effective January, 1999, 2000, and 2001, the capacity release credits were also deducted from the total pipeline transportation and storage capacity costs. Therefore, as succinctly explained by Company Witness Hays in his Rebuttal Testimony, 'customers received the benefit of the capacity release credits twice -- first, monthly through ... the MBR mechanism and then a second time through the use of understated pipeline capacity costs.' BGE Brief, pp. 5-6. [FN3]

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II.

The alternatives for resolving this dispute are set by the positions of the respective parties. BGE claims entitlement to the full amount of the over-refund credit for each accounting period. The Company argues that its recovery of the over-refund of the Capacity Release Credit should not be completely disallowed, or precluded on the basis that it constitutes extraordinary rate relief, or that the extent of recovery be limited to a one-year period adjustment of a billing undercharge. [FN4] In other words, the Company's argument, in its totality, claims that the denial or disallowance of any portion of the adjustment of the over-refund would be a punishment that works to the detriment of both the Company and ratepayer.

The Staff opposes the Company's claim to a recovery of the over-refund of Capacity Release Credits. Staff, while acknowledging that the Company did undercharge its customers by its erroneous calculation of the adjustment for the Capacity Release Credit to the extent of \$9.4 million, contends that, applying the provisions of COMAR 20.55.04.05E, 'BGE is entitled to recover to no more than the portion of the undercharges that occurred during the 12-month period preceding the date on which the error was discovered.' Staff Brief, pp. 6-7. According to Staff, the limited extent of the Company's entitlement to recovery is described as follows:

Staff witness Faulhaber presented evidence regarding the appropriate amount of the \$9.4 million undercharge that BGE is entitled to recover under COMAR. Staff witness Faulhaber determined that the correct amount is \$1,658,013. Staff witness Faulhaber also notes that BGE recovered \$606,017 of the undercharge during the January 2002 billing month. Accordingly, the outstanding balance is \$1,051,996. Staff witness Faulhaber recommends that BGE recover the \$1,051,996 through the Special Actual Cost Adjustment ('Special ACA') factor. Although the Special ACA factor was intended to include transitional costs to reconcile the initial and modified MBR programs and was not designed to recoup undercharges not related to the transition, Staff witness Faulhaber is of the opinion that using the Special ACA factor is an administratively efficient means for recouping the \$1,051,996. Accordingly, the Special ACA should be set at 0.34 cents/therm. Staff witness Faulhaber also recommends that the recovery period occur over twelve months or sooner if BGE collects the \$1,051,996 prior to the expiration of the 12-month period. Staff Brief, p. 7.

OPC also opposes the Company's effort to recover the over-refund of the Capacity Release Credit. In general, OPC argues that BGE should be denied any recovery of the over-refund amount. '[T]he Commission should deny BGE's request for recovery of the \$9.4 million of alleged prior-period under-recoveries due to BGE's own inability to perform its MBR calculations correctly. BGE has already obtained large collateral rewards for making these mistakes, and it would be an unnecessary double burden on customers to allow BGE to 'correct' these mistakes now by charging its customers for an additional \$9.4 million.' (Direct Testimony, OPC Wit-

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ness Ralph E. Miller, p. 32.) Alternatively, if the complete refund is not denied, then OPC urges that the extent of any recovery should be limited to the last 12 months of the most recent accounting period. In that regard, OPC is in agreement with the Staff position that the over-refund recovery should be based on the regulatory standard reflected by COMAR 20.55.04.05E.

III.

The parties are in agreement in their characterization of this disputed claim as an 'over-refund' of the Capacity Release Credits to BGE gas customers. This characterization provides the basis for an analysis that supports each party's position with respect to the extent of the recovery being sought. For BGE, the Company suggests its claim for recovery is justified because its 'customers received the benefit of the capacity release credits twice -- first, monthly through ...the MBR mechanism, and then a second time through the use of understated pipeline capacity costs in the Capacity Reservation Reconciliation Adjustment.' (Emphasis added.) (Direct Testimony, BGE Witness John L. Hays, pg. 3.) Staff, in its characterization of the claim as an 'over-refund,' has determined that the extent of any recovery is based on the application of COMAR 20.55.04.05E. According to the Staff position, treating this mistake as an 'over-refund' of capacity release credits amounts to an undercharge for services that is to be treated as a billing error to customers. Under this view, any recovery for the error is limited because 'retro-active billings may not be for undercharges which occurred more than 12 months before the discovery of the error.' Staff Initial Brief, pg. 6.

A close scrutiny of these arguments suggests, however, that characterizing this claim as an 'over-refund' of capacity release credits misses the mark. The error that is the basis for the Company's claim occurs not in the calculation of the capacity release credit. There was no mistake made in that calculation. [FN5] Rather, the mistake was made in the computation of the Annual Capacity Reservation Adjustment. This computation was performed by incorrectly applying the capacity release credit to the actual amount of pipeline capacity costs. BGE repeated this error over the accounting time periods from 1999 through 2001. The consequence of this error appears not as an 'over-refund' of Capacity Release Credit, but instead is an 'under-recovery' of pipeline reservation costs. This resulting 'under-recovery' is attributable to an error in computing the Annual Capacity Reservation Adjustment, the starting point for resolving the question presented. When viewed from this perspective, resolution of the parties' dispute is clear. That resolution is dictated by the terms of the tariff. [FN6]

The Capacity Reservation Adjustment is a balancing account used to track the difference between pipeline transport and storage capacity costs and revenues. It is a mechanism that allows for the recoupement of any over- or under-recovery of revenues. Specifically, the tariff provides:

BGE accumulates any difference between the actual cost of pipeline transporta-

tion and storage capacity plus \$1.625 million, and the revenues collected from the Capacity Reservation Adjustment, the Pipeline Storage Capacity Price and the Pipeline Transportation Capacity Price for the 12 months ended November. At that time, the balance is amortized over 12 months and is applied as an adjustment to the Capacity Reservation Adjustment for the following year. See, BGE Gas Commodity Price Tariff, Paragraph C.

The operation of this tariff and the resolution of this case is guided by the Commission's decision in *Re Baltimore Thermal Energy Corporation*, 80 Md. PSC 305. In that case, a steam heat utility, through the use of the annual 12-month review of the Actual Cost Adjustment ('ACA') mechanism, sought to recover payments that were the result of billing mistakes that occurred in annual review periods outside the current period. In the annual review period ending November 1988, the utility sought to recover a 1986 payment of \$71,263 to BGE. The utility had failed to include the BGE payment in the 1987 annual review due to a 'mistake or two' of its accountants. *Id.* at 307. Consequently, the utility was seeking to recover the BGE payment two years and two annual reviews after the accounting mistake was disclosed. *Id.* In rejecting the utility's claim, [FN7] the Hearing Examiner concluded that: (1) the inclusion of the 36-month-old change in the ACA was contrary to the language in the tariff that contemplated a 12-month timeframe; (2) the purpose of an ACA is to reconcile fuel costs and FRA revenues from the preceding year; (3) the utility's adjustment is offensive to the notions of timely litigation, principles of finality and the objective for repose. *Id.*, pp. 308-309. The principles enunciated in the rationale of this decision provides the framework that supports the resolution of this case.

As applied in this case, calculation of the Capacity Reservation Adjustment in January 1999 effects an adjustment for any over- or under-recovery for the 12 months ended November 1998. The year 2000 adjustment covers the balance for 12 months ended November 1999; and the January 2001 adjustment reflects the balancing of revenues for the 12 months ended November 2000. Thus, the mechanism of this tariff puts in place a scheme that specifies a timeframe for adjustment of any over- or under-recovery of revenues. The tariff requires that revenues actually collected over a 12-month period from pipeline capacity storage and transportation is balanced against the actual pipeline capacity cost. At the end of that period, the balance is amortized over 12 months and applied as an adjustment over the coming months to reflect either the over- or under-recovery of revenues from the prior 12-month period. By its language, this tariff limits any adjustment to a 12-month period.

Contrary to the 12-month limit of the tariff, BGE seeks to secure an adjustment for the under-recovery of pipeline capacity costs over a 36-month period. According to BGE, '[t]he facts and circumstances of this particular adjustment, as well as the numerous prior period adjustments [FN8] previously made by the Company, plainly warrant that the Company be allowed to recover the ... over-refund.' BGE Brief, pg. 19. By characterizing its claim as an effort to recover the 'over-re-

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fund' of capacity release credits, the Company attempts to avoid the limitation of the tariff. However, the unambiguous language of the tariff makes this attempt untenable. To allow recovery of a 36- month error in computing the Annual Capacity Reservation Adjustment, under the guise of recovering an 'over-refund' of capacity release credits, clearly exceeds the boundary of the tariff. Consequently, BGE is entitled to recover for the 'under-recovery' of pipeline reservation costs through application of the Capacity Reservation Adjustment determined in the accounting period for the year 2001. [FN9]

IT IS, THEREFORE, this 18th day of December, in the year Two Thousand Two,

ORDERED: (1) That the Company shall adjust its accounts to correct its error in understating its calculation of the Capacity Reservation Adjustment for the accounting period for the year 2001.

(2) That Baltimore Gas and Electric Company shall file its proposed accounting treatment for recovery of the 'under-recovery' of pipeline reservation costs through application of the Capacity Reservation Adjustment for the year 2001 accounting period within 30 days of the issuance of a final order in this case.

(3) That this matter is hereby continued and that a further hearing shall be held prior to August 1, 2003.

(4) That this Proposed Order will become a final Order of the Commission on January 18, 2003, unless before that date an appeal is noted with the Commission by any party to this proceeding as provided in Section 3- 113(d) (2) of The Public Utility Companies Article, or the Commission modifies or reverses the Proposed Order or initiates further proceedings in this matter as provided in Section 3-114(c) (2) of The Public Utility Companies Article.

David L. Moore
Hearing Examiner
Public Service Commission of Maryland

FOOTNOTES
Order

FN1 Staff filed a corrected version of its Reply Memorandum on February 24, 2003.

FN2 The original mechanism was modified through a settlement supported by BGE, the Staff and OPC. The Proposed Order approving the settlement became an Order of the Commission in Case No. 8860 on July 6, 2001.

FN3 The factual record in this case is neither extensive nor difficult. Indeed, the essential facts are not in controversy. The controversy concerns the characterization that may be applied to those facts and the standard to apply in reach-

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ing the ultimate decision.

FN4 The Commission's Staff cannot waive the Commission's regulations. Consistency in legal arguments with Staff's position in this case therefore suggests that a waiver of COMAR 20.55.04.05(E) should have been requested from the Commission in order for Staff to agree to settle Case No. 8511(z).

FN5 GMC v. Public Service Commission, 87 Md. App. 321, 328 (1991), citing Nantahala Power & Light v. Thornberg, 476 U.S. 953, 106 S. Ct. 2349, 90 L.Ed.2d 943 (1986) and Miss. Power & Light Co. vs. Miss. Ex. Rel. Moore, 487 U.S. 354, 108 S.Ct. 2428, 101 L.Ed.2d 322 (1988).

FN6 GMC at 329 citing Nantahala, 476 U.S. at 970, 106 S.Ct. at 2358-59.

FN7 Order No. 2282, Vol. VI, PSC Md. 151 (1915).

FN8 Order No. 28790, Vol. XXVII, PSC Md. 43 (1936).

FN9 Order No. 51157, Vol. XLV, PSC Md. 196 (1954).

FN10 Id., pp. 205-206.

FN11 Order No. 55567, Vol. LV, PSC Md. 59 (1964).

FN12 Baltimore Thermal, at 308.

FN13 The Commission also notes that, in the event a BGE gas retail sales customer does consider the collection of the over-refund to be objectionable for whatever reason, that customer has the option to seek retail gas sales service from a supplier operating on BGE's system and, thereby, largely avoiding the collection of the over-refund.

FN14 See, Transcontinental Gas Pipe Line Corporation, 93 FERC ¶61,114 at 61,322-23 (2000) and Mississippi River Transmission Corporation, 93 FERC ¶ 61,212 at 61,702-03 (2000).

Proposed Order of Hearing Examiner

FN1 The City Gate Index price of gas is the price at the junction of a gas pipeline's delivery system and the utility's delivery system.

FN2 MBR includes a monthly adjustment that provides a credit to the commodity gas price reflecting 90 percent of revenues received by customers as a result of the Company's sale or release of excess capacity of pipeline gas. These same credits were also deducted from the actual amount of pipeline capacity costs when the annual reconciliation of actual costs and collected revenues was performed.

FN3 The 1996 MBR program produces a 73-page spreadsheet that was the basis for

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computing the MBR. That procedure has been simplified and reduced to a 10-page routine. As a result of this simplification, the Company says that mistakes are not likely to occur in the future. BGE Brief, pp. 8-9.

FN4 COMAR 20.55.04.05 allows that where a customer has been undercharged for services, an adjustment or refund must be obtained within the most recent 12 months from discovery of the undercharge.

FN5 The parties are in agreement that the Company properly credited customers for their 90 **percent** share of **capacity release** credit throughout the accounting periods 1999 through 2001. See, Direct Testimony, Staff Witness E. Matthew Faulhaber, p. 12; Direct Testimony, BGE Witness John L. Hays, p. 11.

FN6 Since the decision in this case is based on application of the tariff, the Staff and OPC argument that this 'under-recovery' amounts to a billing error to be determined by COMAR is rendered moot. It should be noted, however, that while the Company's opposition to this argument appears to have merit, it is not necessary to decide this issue in light of the tariff.

FN7 The utility was allowed recovery of a second payment of \$441,920 made in 1987 that was more than 12 months beyond the 12-month period of the tariff adjustment for the annual review of 1989. The utility had not sought timely recovery of this payment due, in part, to a request by Staff that the utility delay its recovery to allow Staff to conduct an investigation. The Hearing Examiner recognized the utility's accommodation to the Staff request as the basis for allowing recovery of a payment that was beyond the 12-month limit of the tariff. This was clearly a special situation that justified the exception. The Hearing Examiner noted his concern that '[t]he Company should recognize, however, that Staff does not have the authority to defer issues.'Id. at 308.

FN8 BGE makes the argument, which is contradicted by Staff and OPC, that there have been previous instances in which prior period adjustments have been made and allowed by Staff and OPC. BGE contends that to now oppose its effort to secure an adjustment for this 'over-refund' is a change of the rules and unfair. Since the language of the tariff determines the resolution of this case, this fact obviates consideration of these arguments. Similarly, the language of the tariff does not permit reliance upon a past pattern or practice of allowing prior period adjustments to extend the 12-month limit of the tariff.

FN9 The parties have raised a number of issues that are directly addressed by this decision. Any issues not specifically ruled upon in this decision have been considered and are otherwise denied.

EDITOR'S APPENDIX
Citations in Text

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[MD.] Re Baltimore Gas & E. Co., Case No. 8860, Order No. 77082, 92 Md PSC 381, July 6, 2001.

[MD.Ct.App.] General Motors Corp. v. Maryland Pub. Service Commission, 87 Md.App. 321, 123 PUR4th 510, 589 A.2d 982 (1991).

[U.S.Sup.Ct.] Mississippi Power & Light Co. v. State of Mississippi ex rel. Moore, 487 U.S. 354, 93 PUR4th 293, 108 S.Ct. 2428, 101 L.Ed.2d 322 (1988).

[U.S.Sup.Ct.] Nantahala Power & Light Co. v. Thornberg, 476 U.S. 953, 74 PUR4th 464, 106 S.Ct. 2349, 90 L.Ed.2d 943 (1986).

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H

Re Washington Gas Light Company

Case No. 8920, Phase II

Order No. 78817

Maryland Public Service Commission

December 2, 2003

ORDER addressing certain issues remaining from a natural gas local distribution company's general rate case. Those issues include line extension policies, the allocation of proceeds from off-system sales or capacity release transactions, and methods of assignment of interstate pipeline capacity.

As to line extensions, the commission approves the company's plan to determine cost responsibility premised on life-cycle analyses rather than a two-year revenue test. However, whereas the company would have relied on an assumed 30- year project life for extensions, the commission adopts a 20-year life-cycle basis instead.

In looking at revenue sharing from off-system sales and capacity release transactions, the commission retains the existing 80/20 formula under which 80% of such proceeds go to ratepayers and 20% to the company and its shareholders. A company proposal to move to a 50/50 sharing plan is rejected as not in keeping with industry norms and as producing an adverse effect for ratepayers.

The commission likewise rejects the company's proposed change in its method of assigning interstate pipeline capacity to delivery service suppliers. The company had sought to impose mandatory assignments of transportation capacity, but the commission points out that nothing in the record indicates that such mandatory assignment is needed in order to assure reliability of service.

P.U.R. Headnote and Classification

1.

SERVICE
sl88

Md.P.S.C. 2003

[MD.] Extensions -- Burden of cost -- Means of determining -- Replacement of two-year revenue threshold -- Reliance on life-cycle analysis instead -- Assumption of 20-year project life for extensions -- Natural gas local distribution company.

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P.U.R. Headnote and Classification

2.

SERVICE
s199

Md.P.S.C. 2003

[MD.] Extensions -- Natural gas local distribution company -- Burden of cost -- Means of determining -- Replacement of two-year revenue threshold -- Reliance on life-cycle analysis instead -- Assumption of 20-year project life for extensions.

Re Washington Gas Light Company

P.U.R. Headnote and Classification

3.

APPORTIONMENT
s30

Md.P.S.C. 2003

[MD.] Expenses -- Natural gas local distribution company -- Line extensions -- Allocation of cost -- Means of determining -- Replacement of two-year revenue threshold -- Reliance on life-cycle analysis instead -- Assumption of 20-year project life for extensions.

Re Washington Gas Light Company

P.U.R. Headnote and Classification

4.

APPORTIONMENT
s47

Md.P.S.C. 2003

[MD.] Revenues -- Natural gas local distribution company -- Off-system sales and capacity release transactions -- Allocation of proceeds -- Rejection of 50/50 sharing formula -- Retention of 80/20 formula -- Industry norm as entitling rate-payers to 80%.

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P.U.R. Headnote and Classification

5.

REVENUES
s5

Md.P.S.C. 2003

[MD.] Proceeds from off-system sales and capacity release transactions -- Allocation of -- Rejection of 50/50 sharing formula -- Retention of 80/20 formula -- Industry norm as entitling ratepayers to 80% -- Natural gas local distribution company.

Re Washington Gas Light Company

P.U.R. Headnote and Classification

6.

SERVICE
s339.4

Md.P.S.C. 2003

[MD.] Natural gas -- Allocation of supply -- Of interstate pipeline transportation capacity -- Rejection of proposed mandatory assignment method -- Factors -- As unnecessary to assure reliability of service -- Local distribution company.

Re Washington Gas Light Company

P.U.R. Headnote and Classification

7.

GAS
s7

Md.P.S.C. 2003

[MD.] Operating practices -- Allocation of supply -- Of interstate pipeline transportation capacity -- Rejection of proposed mandatory assignment method -- Factors -- As unnecessary to assure reliability of service -- Local distribution company.

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Re Washington Gas Light Company

APPEARANCES: Paul S. Buckley and Keith Townsend, for Washington Gas Light Company. M. Catherine Dowling, Megan A. Sperling and James W. Boone, for the Staff of the Public Service Commission of Maryland. Luanne P. McKenna and Richard T. Miller, for the Maryland Office of People's Counsel. Frann G. Francis and V. Lesa Noblitt, for the Apartment and Office Building Association of Metropolitan Washington. David A. McCormick, for the Department of Defense and other Federal Executive Agencies. Odogwu O. Linton, for Baltimore Gas and Electric Company. Jeral A. Milton, for Eastalco Aluminum Company. Marvin T. Griff and Michael N. Kunselman, for Francis O. Day Co., Inc. Philip J. Bray, for The Potomac Edison Company d/b/a Allegheny Power. Kurt L. Krieger and Brian White, for Columbia Gas Transmission Corporation. Joseph J. Zimmerman, for Washington Metropolitan Area Transit Authority.

BY THE COMMISSION:

This is the second phase of a two-phase proceeding. In the first, a settlement of traditional rate case issues was accepted. [FN1] This phase deals with three issues: the sharing of proceeds from Capacity Release transactions, mandatory assignment of interstate pipeline capacity and the policies governing the extension of Washington Gas Light Company's ('WGL') distribution system.

I. PROCEDURAL HISTORY

The procedural history through the settlement of Phase I was provided in Order No. 78041 issued on September 27, 2002 in this case.

On November 26, 2002, WGL filed its Direct Testimony. This testimony was taken from WGL's original filing in March 2002 and reflects the testimony on those issue areas excluded from Phase I. The issues for Phase II were further refined in a Ruling issued on January 24, 2003. The Commission's staff ('Staff'), the Office of People's Counsel ('OPC'), Pepco Energy Services ('PES') and the Apartment and Office Building Association of Metropolitan Washington ('AOBA ') filed the Direct Testimony of their respective witnesses on March 24, 2003. WGL, OPC and AOBA filed Rebuttal Testimony on April 24, 2003. The hearing was held on May 12-13, 2003, Initial Briefs were filed June 9 and Reply Briefs were filed June 23, 2003.

II. WGL'S LINE EXTENSION POLICY

A. WGL's Proposal and Positions of the Parties

WGL's Tariff provides that the Company will bear the cost of any necessary extension or enlargement of mains to the extent of two years of estimated revenues. Costs in excess of such estimate are paid by the customer desiring the gas service. The Company also bears the cost for service pipe installation when the length required between the property line and the meter is 115 feet or less or, in the case of a single service pipe installed for four or more dwelling units, the

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distance does not exceed 50 feet per unit up to a maximum of 750 feet. To the extent the required investment exceeds two years of estimated revenues, WGL is authorized to require a contribution of the estimated cost from the customer. [FN2]

WGL proposes to change its line extension policy so that an evaluation of each application for gas service will be made to determine whether the installed service will provide, over its economic life, a return on equity equal to or greater than the equity return authorized by the Commission for WGL at the time of the evaluation. If such a return is projected, WGL will install the service at no direct cost to the customer. If such a return is not projected, then WGL proposes to require a deposit, as a precondition to construction, from the applicant in an amount calculated to meet the authorized return plus an allowance for income taxes. The elements included in the calculations of the economic test and of the deposit are included in WGL's proposed tariff.

According to WGL, the proposed change will appropriately assess the cost of the extension and assure that cross-subsidies from existing customers do not occur. The Company asserts that the proposed extension provisions are currently applied in its service territory in the Commonwealth of Virginia and have been so for approximately seven years.

The proposed change is supported by Staff and is opposed by AOBA. OPC supports the underlying principle of life-cycle analysis for line extension determinations but asserts that several modifications are necessary and, absent those modifications, recommends rejection of the proposed change.

Staff argues that the proposed change from a two-year revenue test to a life-cycle analysis is an improvement because it should prevent uneconomic extensions in the future, brings any customer contribution more in line with the cost of the extension and should result in an overall lower cost to provide service to all ratepayers.

AOBA asserts that the proposed change provides no real assurance of economic feasibility and considers only one limited aspect of the potential cross-subsidies. Additionally, AOBA asserts that the proposal is problematic for a number of other reasons including that WGL is both the source of the data used in the analysis and the party performing the analysis, that it does not necessarily produce more accurate results, that it relies on an explicit authorized rate of return that may not be present in a settled (as opposed to a fully litigated) rate case and that it does not address other sources of alleged cross-subsidies such as the replacement of cast iron and bare steel mains and service lines.

OPC supports the principle of life-cycle analysis for line extension determinations but believes that several modifications are necessary. OPC asserts that the 30-year project life used to calculate the customer contribution is too long because there is no reasonable assurance that a new customer will actually use gas

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for that entire period and a shorter period would reduce the risk of recovery through base rates by raising the contribution required from the customer requesting service. OPC also argues for a more detailed explanation of the life-cycle analysis in the tariff and the inclusion of explicit language to inform customers of their right to challenge the Company's computation.

B. Discussion and Decision on Line Extensions

[1-3] The proposed change to a life-cycle analysis for line extension determinations is accepted with certain modifications. WGL has shown, by a preponderance of the evidence, that the lifecycle analysis should better protect existing ratepayers from uneconomic system expansions and better reflect the connection between cost causation and cost recovery than the methodology it replaces. Uneconomic expansions of the systems will be less likely because the life-cycle analysis will provide a cost estimate that more closely reflects the actual cost of the project than the estimate produced under the previous methodology. To the extent the return on the project does not equal or exceed the Company's authorized return, the project's proponent will be asked for a contribution sufficient to do so. The customer's contribution toward the project will avoid both the passing of the costs onto system customers through base rates and the erosion of the return dollars actually realized by the Company. Further, while not perfectly reflecting the actual costs of any given project, the estimates produced by the life-cycle analysis will more accurately tie cost causation to cost responsibility. A similar policy goal has been an important part of the reason for gradually adjusting the responsibility for return dollars on WGL's system over the years.

The modifications ordered herein to be made to WGL's original proposal will substantially address the concerns raised by OPC. A 30-year life-cycle is lengthy and creates a higher risk for the system that natural gas will not be used for the complete period. Therefore, in order to reduce this risk, WGL is directed to shorten the period to 20 years and, for the same reason, to use a five-year life-cycle for proposed extensions with estimated loads in excess of 500,000 therms per year.

OPC's other proposed changes are not accepted. Customers have an existing and continuing right to challenge any aspect of an application of its Tariff by WGL. There is no need to insert specific language in WGL's Tariff indicating that the right to challenge the application of the line extension provisions is somehow different from the right to challenge any other provision. Furthermore, there is no need to add detail to the Tariff by requiring an expanded explanation or illustration of the life-cycle analysis and calculation. A customer who questions WGL's decision on a project or the amount of the contribution requested would be within its rights to request an explanation of how WGL arrived at that decision or that amount. The details therefore can be reviewed on a case-by-case basis absent a particular reason for a broader inquiry or more detail contemporaneous with the project analysis.

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AOBA's concerns are acknowledged but overstated. In an absolute sense the observation that the life-cycle analysis does not provide real assurance of economic feasibility and that it does not completely address the potential for or multiple sources of cross-subsidies is accurate. However, the life-cycle analysis is an improvement in these two areas. WGL asserted that it applies a similar methodology in Virginia and has done so for some time. AOBA did not make a case that the extension policy applied by WGL for the past seven years in Virginia increased the frequency of uneconomic extensions of the system or increased the number of or severity of any cross-subsidies.

Regarding AOBA's other criticisms, it is sufficient to note that they do not undermine the life-cycle analysis proposal so much as raise possible implementation issues for which there are adequate or potential remedies short of rejecting a proposal that improves over the status quo. The fact that WGL is the source of the data and the analyst is not, in itself, a sufficient concern because it is true of many aspects concerning a regulated entity. Customers of the regulated service have a continuing ability to challenge WGL's decisions and a ready forum at this Commission. Moreover, no evidence of abuse or improper discriminatory conduct by WGL in the application of the life-cycle analysis to projects in the Virginia service territory is included in the record.

The fact that the life-cycle methodology requires an explicit authorized return is likewise not a basis for its rejection. Such an authorized return is provided in Case No. 8959 for life-cycle analysis and calculations into the foreseeable future. Any future alterations based, for instance, on a settlement of a rate case, can be dealt with at that time.

III. CHANGE IN THE RATIO FOR SHARING CAPACITY RELEASE REVENUE

A. WGL's Proposal and Positions of the Parties

In early stages of this proceeding the issue of the appropriate level of revenue sharing potentially included much broader issues concerning a gas asset management approach involving a so-called Strategic Alliance. In a Ruling dated January 24, 2003, the issue was narrowed to a consideration of whether WGL's proposal to change the existing revenue sharing ratio of 80 percent to ratepayers and 20 percent to WGL to a 50/50 ratio. The Ruling clarified that the Strategic Alliance issues would only be relevant in this proceeding to the extent WGL relied on the Strategic Alliance to support its proposed change to a 50/50 ratio.

The Commission originally approved, with certain conditions, an 80/20 sharing of the gross margin from off-system sales that utilized WGL's existing capacity and commodity assets by letter order dated May 14, 1997. In its application filed on May 1, 1997, WGL noted that the proposed 80/20 sharing was the same ratio that the Commission approved for similar programs conducted by Baltimore Gas and Electric Company and Columbia Gas of Maryland. WGL also noted that it was already author-

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ized to share revenues from off-system sales on a 50/50 ratio when such sales did not utilize existing pipeline assets that WGL had under contract to serve firm sales customers.

WGL now proposes to change the ratio from 80/20 to 50/50 and, in its pre-filed testimony of November 25, 2002 and April 24, 2003, offers as reasons for the change that:

1. New incentives are needed for an entity to take the risks associated with asset management (WGL Exh. 3, p. 2);
2. WGL deserves compensation for securing the potential for providing significant additional value for ratepayers through the creation of the Strategic Alliance (WGL Exh. 3, p. 24 and WGL Exh. 4, p. 8); and
3. The Strategic Alliance provides a different dimension of litigation risk for WGL (WGL Exh. 4, p. 8).

In its Initial Brief WGL provides arguments beyond the testimony of its witnesses in support of changing the ratio to 50/50. WGL argues that the District of Columbia Public Service Commission adopted the proposed change and that Virginia's Commission is considering it as well. The Company also argues that the Virginia Commission approved a similar proposal for Virginia Natural Gas ('VNG') even though VNG -- unlike WGL -- had no asset management experience. Finally, WGL argues that its proposed 50/50 ratio sharing of net revenues from asset management activities should be approved because the Commission allows BGE to retain 50 percent of the savings it realizes in gas commodity purchases at below industry indices under BGE's market-based rates mechanism.

Staff, OPC and AOBA all filed testimony opposing the proposed change and/or offering modifications or alternatives. According to Staff, WGL has a duty under law to prudently manage the assets held to provide firm service without a carrot, much less a larger carrot. Further, Staff argues that WGL has failed to provide credible evidence showing that its share of the revenue should be increased. In particular Staff notes that WGL was unable to quantify its bald assertion that litigation risk would increase as a result of the Strategic Alliance. Staff also argues that WGL is already benefiting from a 50/50 sharing in revenues from offsystem sales utilizing non-firm assets. Finally, Staff proposes to modify the sharing plan to ensure that any portion of the revenue share that is paid to an **asset manager** is deducted from WGL's revenues derived from its existing share of 20 **percent**.

OPC argues that WGL's case in support of the proposed change consists of little more than ambiguous and conclusory statements. According to OPC the need for financial incentives as a catalyst to encourage WGL to participate in the capacity release and off-system sales markets has passed, leaving only WGL's statutory duty to prudently manage the firm-service assets. Moreover, OPC argues that WGL has not

shown any new risks to it nor any additional benefits to ratepayers that would justify increasing WGL's share of the revenues and decreasing the share credited to ratepayers. OPC speculates that the proposal, if accepted, may even operate as a perverse incentive for WGL to increase the costs to ratepayers by contracting for additional capacity, the costs of which would be passed on to ratepayers while WGL would enjoy half of any revenues resulting from its use in off-system sales. Finally, and in the event the Commission determines that an incentive is warranted, OPC proposes an alternative incentive to the existing 80/20 sharing.

AOBA suggests that WGL's support for its incentive proposal is couched more in terms of an argument for an entitlement. In addition to blurring the distinction between an incentive and an entitlement, AOBA argues that WGL failed to identify any new specific risks that WGL will be undertaking. Finally, AOBA asserts that WGL has failed to provide any systematic evaluation that supports its proposed change and that there is nothing in a 50/50 proposal that makes it inherently more equitable or appropriate than some other sharing ratio.

B. Discussion and Decision on Changing the Ratio for Sharing Capacity Release Revenue

[4, 5] Approximately six years ago the Commission approved an 80/20 revenue sharing ratio for WGL off-system transactions that utilized existing capacity and commodity assets. A review of the documents associated with the approval show that the basis for the selection of the 80/20 ratio, as opposed to a different ratio, was essentially that it was the same ratio previously approved for similar transactions by BGE and Columbia. That ratio remains in effect for such off-system transactions by BGE and Columbia.

WGL proposes to change the ratio for its off-system sales transactions. As the proponent of a change, WGL bears the burden. In this particular case, since this proposed change will affect rates charged by WGL, WGL must show that the resulting rates are just and reasonable pursuant to §§ 4-201 and 4-402. The Commission finds that WGL has not met that burden. WGL has not provided sufficient evidence upon which the Commission can conclude that additional incentives are needed. In particular the evidence is inadequate to convince the Commission that there are any new risks, notwithstanding the simple assertion of increased legal risk, or that an additional 30 points in shared revenue is the appropriate compensation assuming there are new risks.

Also unsupported is the implicit assumption by WGL that any increased compensation must be in the form of a greater share of revenues. The revenues under discussion are monitored by the Commission in connection with its oversight of WGL's purchased gas clause. Revenue sharing, particularly when a third party is involved that may claim its books and records are outside of the Commission's authority to audit, may become an unworkable complication to the review of gas costs required under Maryland law. It is not clear from the record in this case that a fee ar-

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rangement, one that would be more readily susceptible to an annual audit than a revenue-sharing mechanism, is not a superior, from a regulatory perspective, means of compensating a contractor.

As to WGL's second rationale, any additional value for ratepayers to be derived from changes that WGL apparently has in mind are speculative on this record. Moreover, since WGL will continue to receive 20 percent of any increased value, to the extent it increases the value it will increase the amount of the revenue it receives under the existing sharing ratio.

The decisions made by regulatory commissions in other states are often informative for this Commission. However, in this instance, the Commission declines to follow their lead in large part because of the established practice already in this State. If a convincing case had been made to reconsider that practice or even to consider WGL as a special case, the Commission would conduct such an analysis. In this instance, such a case has not been made.

Finally, WGL's reliance on BGE's Market-Based Rate mechanism ('MBR') to support a change in the ratio to 50/50 is misplaced. There is no showing that the sharing mechanism used to encourage BGE's gas commodity purchases is substantially similar in function to the sharing mechanism used to maximize WGL's off-system sales transactions. Furthermore, as AOBA observed, there is nothing intrinsic about a 50/50 sharing that makes it more equitable or appropriate as a matter of policy than an alternative. If an increase of 30 points in WGL's share of the revenues had been accepted, then it may have been appropriate to define the body of revenues to be shared differently than it is currently defined so that any third-party share would be deducted from WGL's share. This does not necessarily result in WGL's absorption of a gas cost. While the Commission agrees that, if the contractor's costs to WGL in performing some aspect or aspects of the purchased gas function are verified and not imprudent, they are within the universe of costs to be considered for treatment as gas costs. Accordingly, the Commission does not see a need to make changes at this time and therefore will not act on Staff's proposed modification. Further, since the Commission has decided not to accept an alteration of the status quo at this time, it will not act on OPC's proposed modification.

IV. WGL'S PROPOSAL TO REQUIRE MANDATORY ASSIGNMENT OF INTERSTATE PIPELINE CAPACITY TO DELIVERY SERVICE SUPPLIERS

A. WGL's Proposal and Positions of the Parties

WGL proposes to modify the capacity management position of its firm delivery service program. WGL proposes that it be authorized by the Commission to make assignments of firm interstate pipeline transportation capacity to delivery service suppliers operating on its distribution system and that those suppliers be required to accept those assignments. The shorthand term for this issue is mandatory as-

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signment.

WGL offers three reasons in support of this proposal. First, according to WGL, mandatory assignment is necessary to ensure the reliable operation of the distribution system. WGL asserts that reliable distribution system operations are undermined because suppliers have not contracted for significant primary point, firm interstate transportation capacity to WGL's city gate. Second, WGL asserts that incremental firm transportation capacity is generally unavailable on the interstate pipeline serving WGL's city gates unless one is willing to participate in an open season process and make a multi-year contract commitment to the interstate pipeline company. WGL states that suppliers have not, and apparently believes they will not, make such commitments. Finally, WGL asserts that suppliers are using secondary firm and interruptible transportation on the interstate system to meet their delivery obligations into WGL's distribution system. As the operator of the distribution system and as the public service company with the obligation to provide natural gas service to those customers for whom it has undertaken service (and has not been released from that obligation by the Commission through a grant of abandonment), WGL claims that it does not believe that it can depend on secondary firm or interruptible capacity for delivery to WGL's city gate under extreme weather conditions.

WGL's proposal for mandatory assignment is opposed by Staff, AOBA and PES. Staff argues first that mandatory assignment is not necessary to maintain the reliability of the distribution system. Second, Staff asserts that WGL has failed to show that the existing voluntary assignment program option to assign storage and peaking and the penalty provisions are not adequate to ensure deliveries into the system. Finally, according to Staff, mandatory assignment will have a significant negative impact on retail choice by restricting the manner in which suppliers can conduct business on the interstate pipeline system necessary to perform their contractual commitments to customers on WGL's distribution system.

AOBA's opposition focuses on an argument similar to Staff's third argument. According to AOBA, mandatory assignment of transportation capacity means that WGL will control interstate capacity into its city gates. That control will effectively limit retail gas competition to the commodity component. AOBA asserts that the suppliers are already plagued by slim margins and that effectively precluding contracting for capacity in the transportation markets, and thereby precluding a means for suppliers to distinguish themselves, will strangle the suppliers and, ultimately, retail competition.

PES argues that each of the three reasons offered in support of mandatory assignment by WGL fail. First, PES supports its claim that mandatory assignment is not necessary to reliable operation of the distribution system and suggests that it is actually a means for WGL to ensure that it recovers the cost of interstate pipeline capacity directly from the customers that have elected to purchase gas from a supplier. Second, while not directly contesting WGL's assertion that incre-

mental firm transportation capacity is generally unavailable to WGL's city gate, PES argues that the problem implied by any lack of such capacity will be cured if WGL renews its existing contracts when they expire. PES notes that WGL's witness stated that contract renewal would be undertaken by WGL if mandatory assignment were not authorized, with the possibility of additional capacity acquisitions by WGL to back up all the capacity directed to WGL's city gates. Additionally, PES cites to WGL's own data for the proposition that delivery failures into WGL's system are few, both in numbers of events and undelivered volumes, amounting to .17 percent or less, and that such events would not have been completely avoided even if mandatory assignment had been available. Moreover, PES offers WGL's own statements in its 10-K filings for the years ending September 2001 and September 2002 regarding the sufficiency of existing interstate capacity and WGL's ability to cover supplier shortfalls to refute the testimony of WGL's witnesses on system reliability. Third, PES notes that, under WGL's existing Tariff, it has the authority to assign primary transportation capacity to those suppliers operating on its distribution system who are unable to demonstrate to WGL that they have sufficient capacity. Therefore, PES argues, WGL should utilize the authority it has to assign capacity when necessary and not attempt to dictate to suppliers that have obtained adequate capacity how they will conduct their business.

B. Discussion and Decision on Mandatory Assignment

[6, 7] WGL has failed to make the case for accepting mandatory assignment of interstate transportation capacity. First, WGL relies on its supplier of last resort model, to lay the foundation for mandatory assignment. However, the Company failed to explain how the model differs from WGL's long-standing obligations as a public service company holding franchises in Maryland and subject to the provisions of the Public Utility Companies Article. In its Initial Brief, however, WGL notes that the testimony was filed before Order No. 77987 was issued in Case No. 8933 and that Order effectively resolved the supplier of last resort issue raised by the Company. [FN3] In light of the lack of any authority for, or explanation of, the model and in light of the Commission's pronouncements in Order No. 77987 this model, as a foundation for mandatory assignment, is deemed withdrawn.

Second, the testimony and evidence relied on by WGL does not provide a basis to conclude there is a sufficient failure on the part of the suppliers to deliver the quantities of gas into the distribution system necessary to meet their obligations to their customers to support acceptance of mandatory capacity assignment. WGL's Direct Testimony endeavors to support its need for mandatory assignment but is not convincing. WGL testifies that 'it cannot find significant evidence of a liquid upstream market for design day transportation capacity.' This statement, in the Commission's view and a lack of record evidence to the contrary notwithstanding, does not indicate a change in operating circumstances on the interstate system. Also, WGL's professed belief that it cannot depend on capacity that was 'not contracted or designed for delivery ...under extreme weather conditions' appears to be at odds with its past modus operandi and may be an extreme or unnecessary

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standard to set. The fundamental problem for WGL's position, however, is that there is not a basis in the record in this case that causes the Commission to conclude that there has been a change in how operations are conducted on the interstate system facilitating deliveries to WGL's city gate or that WGL's standard for capacity used by third parties for deliveries into its city gates is, or ought to be, as high as WGL's testimony professes.

Third, the record does not support the conclusion that implementation of mandatory assignment would lead to 100 percent reliability in deliveries to the system. In its Rebuttal Testimony, WGL offers six instances on two of WGL's interstate pipelines, Columbia and Transco, from the winter of 02-03 in support of its proposed mandatory assignment. WGL does not, however, draw any particular connection between any of the six events and harm to WGL's system or to how mandatory assignment would have prevented the event or any harm. PES argues that the first three events applied only to the secondary capacity and the second three generally indicate a reduction in reliability on the pipelines. It is not necessary to accept PES's argument to conclude that the connection has not been made between the events, any harm and the remedy represented by mandatory assignment. However, it is worth noting that the interpretation of the events offered by PES is more convincingly drawn than that offered by WGL. Therefore, at least at this time, mandatory assignment appears to be an inadequate solution to an unsubstantiated problem.

Beyond that, mandatory assignment raises serious, potential problems for gas suppliers and may indeed pose a threat to the future of customer choice. The testimony in the record indicates that supplier margins are thin. Accepting that as true does not so much resolve the issue as color the environment. In an environment of thin margins adding perhaps unnecessary costs by reducing a supplier's alternatives for securing delivery of the gas places additional pressure on suppliers, to the point where it may not be supportable. If this is the case then, for no real benefit (for the two reasons above), customer choice would be jeopardized on WGL's system by mandatory assignment. This is a risk that need not be taken.

WGL correctly feels the responsibility for the reliable operation of the distribution system. WGL is, as the public service company, required to ensure that the distribution system functions to reliably supply natural gas to all customers -- whether they are firm sales customers of WGL or of suppliers selling into WGL's system. [FN4] How WGL decides to meet its public service company obligations is generally a matter for its operational expertise and business judgment although subject to oversight by this Commission, particularly in light of §§ 4-101, 4-402, 5-103 and 5-202 of the Public Utility Companies Article of the Annotated Code of Maryland.

In this case, WGL's proposal is not accepted. That decision is based on the conclusion that a sufficient reliability issue has not been shown and that the proposed solution would probably not satisfy the problem if it existed, although it

94 MD PSC 409
94 Md.P.S.C. 409, 2003 WL 23574233 (Md.P.S.C.)
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may satisfy a cost allocation issue. Nevertheless, the Commission appreciates the implications in WGL standing ready to provide gas molecules to those firm customers for whom it is currently providing transportation service on its distribution system and, at the same time, continuing to serve its own firm sales customers. In WGL's case the challenges are perhaps magnified by the fact that its system serves three jurisdictions. This is, however, the current status for gas customers, distribution system operators and gas suppliers in Maryland and it will require sincere efforts by all to continue to enable gas customers to enjoy reliable distribution service and choice in supplier at reasonable rates and costs.

V. CONCLUSION

IT IS, THEREFORE, this 2nd day of December, in the year Two Thousand Three, by the Public Service Commission of Maryland,

ORDERED: (1) That the proposed changes to the Tariff provisions on line extensions are accepted as modified consistent with part II.B above.

(2) That the proposed modification of the ratio for sharing capacity release revenue is rejected consistent with part III.B above.

(3) That the proposed changes to the Tariff provisions which would institute mandatory assignment of interstate pipeline capacity are rejected consistent with part IV.B above.

J. Joseph Curran III
Commissioner/Panel Chairman
Ronald A. Guns
Commissioner
Andrew P. Mosier, Jr.
Chief Hearing Examiner

FOOTNOTES

FN1 Order No. 78041, issued on September 27, 2002.

FN2 Costs not recovered directly from the party requesting service are recovered as a component of base rates from all firm service customers.

FN3 In its Initial Brief WGL suggests that the issue is not now whether mandatory assignment should be accepted but a choice between mandatory assignment and a proposal for WGL to recover costs of interstate capacity through its Gas Supply Realignment Charge. The Commission declines the suggestion. WGL's Rebuttal Testimony criticizes the proposal to rely on the Realignment Charge as, at best, a partial solution and then offers additional criticisms. Moreover, the record on using the Realignment Charge is poorly developed in this proceeding. OPC notes in its Reply Brief that using the Realignment Charge is an issue best left for litigation and

94 MD PSC 409
94 Md.P.S.C. 409, 2003 WL 23574233 (Md.P.S.C.)
(Publication page references are not available for this document.)

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decision in Case No. 8951. The Commission agrees with OPC on this point.

FN4 Re Retail Sale of Natural Gas, Case No. 8933, 93 Md. PSC 239 at 243-244 (2002).

EDITOR'S APPENDIX

Citations in Text

[MD.] Re Retail Sale of Natural Gas, Case No. 8933, Order No. 77987, 93 Md PSC 239, 219 PUR4th 323, Aug. 28, 2002.

[MD.] Re Washington Gas Light Co., Case No. 8920, Phase I, Order No. 78041, 93 Md PSC 265, 221 PUR4th 478, Sept. 27, 2002.

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H

Pennsylvania Public Utility Commission
 v.
 National Fuel Gas Distribution Corporation
 Rulemaking Proceeding 00016789
 Rulemaking Proceeding 00016789C0001

Pennsylvania Public Utility Commission
 July 23, 2002

*1 Commissioners Present: Glen R. Thomas, Chairman, Robert K. Bloom, Vice-Chairman, Aaron Wilson, Jr., Terrance J. Fitzpatrick, Kim Pizzingrilli

OPINION AND ORDER

BY THE COMMISSION:

Before the Commission for consideration and disposition are the Recommended Decision of Administrative Law Judge (ALJ) James D. Porterfield, issued on June 20, 2002, in the above captioned purchased gas cost (PGC) proceeding, and the Exceptions thereto filed by National Fuel Gas Distribution Corporation (NFGD) on June 27, 2002. On July 2, 2002, the Office of Consumer Advocate (OCA) filed Reply Exceptions. Also before us for consideration is the July 15, 2002 Letter Request, filed by the Parties, requesting this Commission to defer and postpone ruling on the sole issue reserved for litigation in this proceeding (AM-60 Firm Transportation (FT) contract).

I. HISTORY OF THE PROCEEDING

On January 2, 2002, pursuant to Section 1307(f) of the Public Utility Code (Code), 66 Pa. C.S. § 1307(f), NFGD filed its preliminary supporting information for its PGC for the 12-month period ending July 31, 2003. On February 1, 2002, NFGD submitted its definitive filing. NFGD filed Supplement No. 7 to Tariff Gas-Pa. P.U.C. No. 9, proposing to decrease its PGC rate by \$0.1932/Mcf, from the then current level of \$5.2883 per Mcf, to \$5.0951. NFGD subsequently revised its proposed PGC reduction to \$0.3653/Mcf. (NFGD PGC Statement No. 6, p. 12).

On January 14, 2002, the Office of Trial Staff (OTS) filed a Notice of Entry of Appearance; on January 22, 2002, the OCA filed a Formal Complaint against NFGD's proposed PGC rates; on February 5, 2002, the Office of Small Business Advocate (OSBA) filed a Notice of Intervention; and on February 26, 2002, the National Fuel Gas Industrial Intervenors (NFGII) filed a Petition to Intervene which was granted.

The Commission held a Prehearing Conference on February 12, 2002, and thereafter

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conducted an evidentiary hearing [FN1] in Harrisburg on May 1, 2002. On May 10, 2002, NFGD, the OTS, the OSBA, and the OCA submitted a Stipulation in Partial Settlement of The Rate Investigation, pursuant to 66 Pa. C.S. § 1307(f) (Stipulation). The sole issue remaining for litigation was NFGD's one-year extension of its contract with NFGD's affiliate, National Fuel Gas Supply Corporation (NFG Supply) for FT service for incremental capacity on the Line AM-60 pipeline.

On May 14, 2002, NFGD and the OCA filed Main Briefs, and on May 21, 2002, Reply Briefs were filed by NFGD and the OCA. The Recommended Decision of ALJ Porterfield was issued on June 20, 2002. As noted above, on June 27, 2002, Exceptions were filed by NFGD and on July 2, 2002, the OCA filed Reply Exceptions.

Additionally, on July 15, 2002, NFGD filed a Letter Request that the Commission defer and postpone ruling on the issue reserved for litigation in this proceeding (AM-60 FT contract). NFGD and the OCA requested the additional time to continue discussions in an attempt to resolve the AM-60 FT contract issue.

*2 II. THE SETTLEMENT

The ALJ concluded that the Stipulation, which is proposed to become effective for service furnished on and after August 1, 2002, is in the public interest. Accordingly, the ALJ recommended adoption of the Stipulation, including the Proposed Findings of Fact.

The Stipulation provides for a PGC rate--for the most widely used sales rate schedules--of \$5.4124 per Mcf (the PGC amount). This is a reduction of \$0.3522 from the \$5.7646 rate that became effective on May 1, 2002, under the Commission's procedures for quarterly updates of the PGC rate. The PGC rate proposed in the Stipulation is subject to updates for actual over-or under-recoveries of purchased-gas costs and revised projections of purchased-gas costs through June 30, 2002. The proposed rate is also subject to the resolution of the litigated issue, discussed below, involving the Line AM-60 FT contract with NFGD's affiliate, NFG Supply.

The Parties, in their statements in support of the Stipulation, express the opinions that adoption of the terms and conditions of the Stipulation is consistent with the public interest and is in the interest of NFGD's customers. In particular, the statements highlight two themes.

First, the Stipulation establishes a single mechanism for sharing revenues and savings with PGC customers from off-system sales, releases of pipeline or storage capacity, or both, and from storage-fill contracts. NFGD withdrew its proposal to share revenues from storage-fill contracts beginning in April 2001, and agreed to limit sharing to revenues generated after July 31, 2001. This structure allows NFGD to retain 25 **percent** of net revenues from **off-system sales** and storage-fill contracts and revenues from **capacity releases** beginning August 1, 2001, with the

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remaining 75 **percent** of these revenues flowing to PGC customers. The OTS represented that the amount to be flowed through to PGC customers, as a result of the storage-fill-contract savings, is \$289,599. The structure proposed in the Stipulation provides for the application of a consistent set of economic incentives across these gas and capacity-management activities.

Second, NFGD has agreed to submit additional data and analyses to support the continued sharing of revenue with its PGC customers. In particular, NFGD will furnish (a) more detailed data showing the methodology, assumptions, and formulae used to calculate revenue impacts; (b) expanded historical data for the previous three rate-years to facilitate the identification of trends in the performance of the sharing programs; and (c) an analysis, in 2004, that explicitly reviews program performance and makes recommendations for the continuation, adjustment, or elimination of particular program components. These data and analyses will allow all Parties and the Commission to better assess the efficacy and long-term benefits of the programs to NFGD's PGC customers.

The ALJ concluded that approval and adoption of the terms and conditions of the Stipulation appears to be consistent with the public interest and in the interest of NFGD's customers. For the reasons set forth above and for those reasons set forth in the Appendices C, D, E, and F to the Stipulation, the ALJ recommended that the terms and conditions of the Stipulation be accepted, approved, and adopted without modification, subject to the result of the litigated issue, as being consistent with, or in conformity with, the public interest and consistent with 66 Pa.C.S. §§ 1318 and 1501.

*3 III. DISCUSSION

We note that ALJ Porterfield adopted the proposed Findings of Fact and Standards and Findings contained in the Stipulation (Statutory Findings and Standards). Additionally, we note that ALJ Porterfield made findings throughout his Recommended Decision, which we incorporate herein by reference, unless modified or reversed, either expressly, or by necessary implication, by this Opinion and Order.

We further note that any issue or exception not specifically addressed herein shall be deemed to have been duly considered and will be denied without further discussion. It is well settled that we are not required to consider expressly or at length each contention raised by the parties. (*Consolidated Rail Corporation v. Pennsylvania Public Utility Commission*, 625 A.2d 741 (Pa. Cmwlth. 1993); see generally, *University of Pennsylvania v. Pennsylvania Public Utility Commission*, 86 Pa. 410, 485 A.2d 1217, 1222 (1984)). It should be noted that, for those matters which were not subject to Exceptions and for which we do not modify or reject the ALJ's analysis or conclusions, we are adopting the recommendations of the ALJ.

We also emphasize that it is this Commission's policy to encourage settlements, pursuant to our Regulations at 52 Pa. Code § 5.231. We have stated that 'the res-

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ults achieved from a negotiated settlement or stipulation, or both, in which the interested Parties have had an opportunity to participate are often preferable to those achieved at the conclusion of a fully litigated proceeding.' (52 Pa. Code § 69.401). The general benchmark for determining the acceptability of a settlement is whether the proposed terms of the settlement promote the public interest. (Warner v. GTE North, Inc., Docket No. C-00902815 (Order entered April 1, 1996); Pennsylvania Public Utility Commission v. C S Water and Sewer Associates, 74 Pa. PUC 767 (1991)). We have recognized that, as a compromise of the signatory Parties' position, a settlement arguably fosters the public interest. (Pennsylvania Public Utility Commission v. Philadelphia Electric Co., 60 Pa. PUC 1 (1985)).

In the matter before us, we are guided by our consistent policy of encouraging settlements. Additionally, we note that there is no opposition to the proposed settlement. Accordingly, finding the Stipulation in this proceeding to be reasonable and in the public interest, we hereby adopt the ALJ's recommendation to adopt the Stipulation.

IV. LITIGATED ISSUE

As previously noted, the Parties to this proceeding were unable to amicably agree on one issue. Our analysis of the remaining issue is set forth, *infra*.

The OCA challenged the reasonableness of NFGD's decision to extend, for one year beyond March 31, 2003, its contract with NFG Supply, its affiliate, for Line AM-60 Firm Transportation (FT) capacity (i.e., 30,000 Dth [FN2]). Consequently, the OCA concluded that the costs-- i.e., \$302,508 in the 2002 PGC period--associated with that capacity should be removed from PGC rates because the result of the renewal does not meet the standards of Section 1318 of the Code. [FN3]

*4 The ALJ found that, by failing to seek a more favorable contract with NFG Supply, when there was some realistic likelihood of successful negotiations, NFGD failed to pursue a least-cost fuel-procurement policy and, therefore, failed to show, under the Section 1318 standards, that the proposed PGC rates for the 2002 PGC period are just and reasonable. [FN4] A proper measure of NFGD's failure in this respect is the lost savings from a more favorable contract in the 2002 PGC period or, stated differently, the costs to be incurred for the renewed FT contract in the 2002 PGC period. The renewed contract-year for the FT contract is April 2003, through March 2004; the 2002 PGC period is from August 1, 2002, to July 31, 2003. The monthly charge associated with the FT contract is \$75,627. Four months of the 2002 PGC period (April through July 2003) fall within the FT contract year. Therefore, the FT contract charges identified with the 2002 PGC period are \$302,508. [FN5] The ALJ found that NFGD's final purchased-gas costs for the 2002 PGC period must be reduced by \$302,508 for the PGC rates to be just and reasonable.

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On July 15, 2002, NFGD and the OCA requested the Commission to grant an additional period of time for the parties to engage in continued discussions regarding the AM-60 FT contract issue, with a view to resolving this issue. The Parties also referenced, but did not explain, that the potential resolution is based upon an unidentified 'contingency.' The Parties asserted that resolution of the AM-60 FT contract issue is expected, and the Parties expect to file another Stipulation and Settlement with the Commission. The Parties requested an extension of time until September 30, 2002.

While we appreciate the efforts of NFGD and the OCA to resolve this matter, we are not prepared to grant a two and one-half month extension on the basis of the nebulous assertions contained in the letter filed by NFGD. In order to encourage a timely resolution to the AM-60 FT contract issue we will bifurcate that issue from the remainder of the 1307(f) proceeding.

We will direct NFGD, in conjunction with the Parties to this proceeding, to file by July 29, 2002, (under proprietary seal if appropriate) the details of the agreement in principle referred to in the July 15, 2002 request for an extension of time, including an explanation of the contingency on which the agreement is based. We will use the information submitted to determine whether a further extension is appropriate, otherwise we will make a decision on the AM-60 FT contract issue at the public meeting of August 8, 2002.

Based upon the foregoing discussion, we shall grant in part the request for bifurcation of the AM-60 FT contract issue, consistent with the conditions delineated in this Opinion and Order. Accordingly, we shall postpone action on the ALJ's Recommendation concerning the Line AM--60 contract and the reduction in purchase gas cost of \$302,508 associated with that finding.

V. CONCLUSION

*5 Consistent with the foregoing discussion, we shall approve the Stipulation in Partial Settlement, finding it to be reasonable and in the public interest. Additionally, the request for bifurcation of the AM-60 FT contract issue is granted in part, and we hereby defer and postpone consideration of this issue subject to the conditions delineated herein. Accordingly, the Recommended Decision of ALJ Porterfield is adopted as modified, by this Opinion and Order; THEREFORE,

IT IS ORDERED:

1. That the July 15, 2002 letter request for bifurcation of the litigated AM-60 FT contract issue from the instant 1307(f) gas cost rate proceeding is granted in part, consistent with this Opinion and Order.

2. That National Fuel Gas Distribution Corporation, in conjunction with the Parties in this proceeding, shall file by July 29, 2002, (under proprietary seal if appropriate) the details of the agreement in principle referred to in the July

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15, 2002, letter/request for an extension of time, including an explanation of the contingency on which the agreement is based.

3. That in the event National Fuel Gas Distribution Corporation and the Parties fail to file a satisfactory explanation as set forth herein by July 29, 2002, the AM-60 FT contract issue will be addressed at the public meeting to be held on August 8, 2002.

4. That the Recommended Decision of Administrative Law Judge James D. Porterfield is adopted, as modified by this Opinion and Order.

5. That National Fuel Gas Distribution Corporation's annual Purchased Gas Cost filing made on February 1, 2002, as Supplement No. 7 to Tariff Gas--Pa. P.U.C. No. 9, under Section 1307(f) of the Public Utility Code, 66 Pa.C.S. § 1307(f), not be permitted to go into effect because the initially claimed gas-cost rate is found to be unjust, unreasonable, and, therefore, unlawful, to the extent reflected in the Parties' Stipulation In Partial Settlement of the Rate Investigation Pursuant to 66 Pa.C.S.A. § 1307(f).

6. That the Joint Stipulation In Partial Settlement Of The Rate Investigation Pursuant to 66 Pa. C.S.A. § 1307(f) submitted May 10, 2002, by the Office of Trial Staff, the Office of Consumer Advocate, the Office of Small Business Advocate, and National Fuel Gas Distribution Corporation, at Docket No. R-00016789, is approved.

7. That, upon the filing of a tariff supplement and compliance filing by National Fuel Gas Distribution Corporation, acceptable to the Commission as conforming with this Opinion and Order, and the Stipulation In Partial Settlement Of The Rate Investigation Pursuant to 66 Pa. C.S.A. § 1307(f) referred to in paragraph 6 above, the purchased gas rates established therein shall become effective for service rendered on and after August 1, 2002.

FOOTNOTES

FN1 The Commission received no request for a Public Input Hearing and none was held.

FN2 One Decatherm (Dth) equals 1 million BTUs; 1.045 Dth equals about one thousand cubic feet of natural gas (i.e., an Mcf).

FN3 66 Pa.C.S. § 1318(b) and (f).

FN4 Pa. P.U.C. v. Pennsylvania Gas and Water Co., 75 Pa. P.U.C. 494, 499 (1991).

FN5 See OCA M.B., p. 10, fn 1.

END OF DOCUMENT

H

Re Rochester Gas and Electric Corporation
Case 98-G-1589

New York Public Service Commission
February 28, 2001

***97** ORDER adopting, as modified, a settlement establishing a rate and restructuring plan that reduces the rates of a natural gas local distribution company (LDC) by some \$3 million. The decrease is to be applied in a levelized fashion over a two-year rate term that extends from July 1, 2000 to June 30, 2002. All customers will receive a one-time credit on their bills for the past period and will obtain prospectively a base rate reduction of \$2.8 million annually.

The new rates are designed to provide the LDC with an opportunity to earn an 11% rate of return on common equity. In the event that the LDC achieves a return on equity in excess of 12.5% during any rate year, 90% of the excess would be used to offset deferred costs that may have accumulated during the rate term. The rate and restructuring plan permits the LDC to defer prudent and verifiable costs associated with government mandates, catastrophic events, competition implementation, main replacement, and gas delivery management systems.

The authorized return on equity also would be subject to adjustment for several incentive programs. For example, the 12.5% earnings threshold would be reduced if the LDC fails to complete its mercury regulator replacement program by June 30, 2002 for reasons other than an inability to hire qualified contractors.

The rate and restructuring plan contains provisions to help establish a competitive retail gas market, including a retail access **capacity** program that would allow the **LDC** to **release** upstream **capacity** to marketers who serve small volume **customers** in the **LDC's** service area. In addition, the rate and restructuring plan contains a **capacity** incentive plan consisting of a **capacity** cost incentive and a **capacity** cost imputation. Pursuant to the **capacity** cost incentive, the **LDC** and its **customers** would **share** any savings or increased costs as compared to a baseline level of **capacity** costs. The **capacity** cost imputation would capture for **customers** the savings derived from short-term transactions, including **releases** of off-system **sales**.

The rate and restructuring plan also provides for the establishment of a low-income program, a service quality performance program, a **customer** competition education plan, and a Department of Social Services aggregation program.

1. PUBLIC UTILITIES, § 78

[N.Y.] Natural gas local distribution company -- Rate and restructuring plan -- Rate decrease -- Earnings **sharing** -- Cost deferrals -- Performance incentives -- Settlement.

2. RATES, § 373

[N.Y.] Natural gas -- Two-year rate plan -- Base rate decrease -- Earnings **sharing** -- Cost deferrals -- Performance incentives -- Local distribution company -- Settlement.

3. RETURN, § 26.4

[N.Y.] Reasonableness -- Cost of equity -- **Sharing** of excess earnings -- Rate and restructuring plan -- Natural gas local distribution company -- Settlement.

4. RETURN, § 26.4

[N.Y.] Reasonableness -- Cost of equity -- Performance incentives -- Rate and restructuring plan -- Local distribution company -- Settlement.

5. RETURN, § 92

[N.Y.] Natural gas local distribution company -- Earnings sharing -- Performance incentives -- Rate and restructuring settlement.

6. REVENUES, § 5

[N.Y.] Natural gas -- Earnings sharing -- ***98** Performance incentives -- Rate and restructuring plan -- Local distribution company -- Settlement.

7. EXPENSES, \$ 9

[N.Y.] Ascertainment -- Rate and restructuring plan -- Cost deferrals -- Natural gas local distribution company -- Settlement.

8. EXPENSES, \$ 125

[N.Y.] Natural gas local distribution company -- Deferred costs -- Possible offset by excess earnings -- Rate and restructuring plan -- Local distribution company -- Settlement.

9. RATES, \$ 373

[N.Y.] Natural gas rate design -- Separation of gas costs -- Rate and restructuring plan -- Local distribution company -- Settlement.

10. RATES, \$ 384

[N.Y.] Natural gas rate design -- General service -- Separation of gas costs -- Simplification of structure -- Elimination of largely unused blocks -- Rate and restructuring plan -- Local distribution company -- Settlement.

11. RATES, \$ 384

[N.Y.] Natural gas rate design -- Small general transportation service -- Simplification of structure -- Elimination of largely unused blocks -- Rate and restructuring plan -- Local distribution company -- Settlement.

12. RATES, \$ 384

[N.Y.] Natural gas rate design -- Large general transportation service -- Implementation of revenue requirement reduction -- Rate and restructuring plan -- Local distribution company -- Settlement.

13. MONOPOLY AND COMPETITION, § 58

[N.Y.] Natural gas restructuring -- Promoting retail competition -- Retail access capacity program -- Capacity incentive program -- Sharing of costs and savings -- Local distribution company -- Settlement.

14. SERVICE, § 339.4

[N.Y.] Natural gas restructuring -- Promoting retail competition -- Retail access capacity program -- Capacity incentive program -- Local distribution company -- Settlement.

15. GAS, § 1

[N.Y.] Industry restructuring -- Promoting retail competition -- Retail access capacity program -- Capacity incentive program -- Local distribution company -- Settlement.

16. REVENUES, § 5

[N.Y.] Natural gas -- Capacity incentive program -- Shared savings -- Rate and restructuring plan -- Local distribution company -- Settlement.

17. EXPENSES, § 125

[N.Y.] Natural gas local distribution company -- Capacity incentive program -- Cost sharing -- Local distribution company -- Settlement.

18. RATES, § 125

[N.Y.] Low-income customers -- Residential energy consumer assistance program -- Rate and restructuring plan -- Local distribution company -- Settlement.

19. CONSERVATION, § 1

[N.Y.] Natural gas -- Low-income customers -- Weatherization grant program -- Rate and restructuring plan -- Local distribution company -- Discussion.

***99** 20. SERVICE, § 332

[N.Y.] Natural gas -- Quality performance program -- Penalties for failure to achieve performance targets -- Local distribution company -- Settlement.

21. RETURN, § 36

[N.Y.] Reasonableness -- Factors considered -- Service quality -- Penalties for failure to achieve performance targets -- Local distribution company -- Settlement.

22. MONOPOLY AND COMPETITION, § 58

[N.Y.] Natural gas restructuring -- Promoting retail competition -- Customer education plan -- Local distribution company -- Settlement.

23. MONOPOLY AND COMPETITION, § 58

[N.Y.] Natural gas restructuring -- Promoting retail access -- Department of Social Services aggregation program -- Local distribution company -- Settlement.

24. SERVICE, § 332

[N.Y.] Natural gas restructuring -- Retail competition -- Department of Social Services aggregation program -- Local distribution company -- Settlement.

25. RATES, \$ 375

[N.Y.] Natural gas rate design -- Minimum charge -- Stipulated increase -- Local distribution company.

26. RATES, \$ 375

[N.Y.] Natural gas rate design -- Minimum charge -- Exemption from stipulated increase -- Low-income customers -- Local distribution company.

27. RATES, \$ 125

[N.Y.] Reasonableness -- Low-income customers -- Exemption from minimum charge increase -- Natural gas local distribution company.

28. RATES, \$ 125

[N.Y.] Low-income customers -- Residential energy consumer assistance program -- Netting of costs against revenues -- Local distribution company.

29. CONSERVATION, \$ 1

[N.Y.] Natural gas -- Low-income customers -- Proposed establishment of weatherization grant program -- Grounds for rejection.

30. MONOPOLY AND COMPETITION, \$ 58

[N.Y.] Natural gas restructuring -- Promoting retail competition -- Customer education plan -- Possible funding through system benefits charge -- Local

distribution company.

Before Galvin, commissioner.

BY THE COMMISSION:

Since mid-1998, Rochester Gas and Electric Corporation (RG&E or the company) and other parties have been engaged in on-going settlement negotiations regarding the company's rates and restructuring. The negotiations produced two previous documents that we adopted pursuant to orders dated September 30, 1999 and July 31, 2000. [FN1]

These orders addressed numerous issues including: a capacity release revenue imputation, capacity cost mitigation measures, retail access program improvements, a backout credit for marketers serving retail customers, a mechanism to keep the company whole for customer migration, a single retailer model for natural gas service, management of gas deliveries into RG&E's system, and a communications protocol for marketers.

***100** To complete the process begun by our previous orders, RG&E and other parties now seek approval of a plan dated January 25, 2001 pertaining to the company's rates and restructuring its gas operations. [FN2]

The Joint Proposal contains provisions affecting revenue requirements, rate design, and competition. It also addresses the ongoing restructuring of the company's natural gas business as contemplated in our Policy Statement Concerning the Future of the National Gas Industry in New York. [FN3] The following parties have executed the Joint Proposal: RG&E, Staff, Energetix, Inc. (Energetix), Amerada Hess Corporation, and Dominion Transmission, Inc. RG&E, Staff, and Energetix submitted comments supporting the Joint Proposal; the State Consumer Protection Board (CPB), Mr. Lawrence W. Owens and Mr. Charles A. Straka filed comments opposing adoption of its terms.

REVENUE REQUIREMENT

[1-8] The Joint Proposal would implement a base rate revenue decrease of \$2,806,000 from the levels in effect on June 30, 2000. This decrease would be applied in a levelized fashion over the two-year rate term that extends from July 1, 2000 to June 30, 2002. The expiration of the rate term is intended to coincide with

RG&E's electric retail rate plan (Case 96-E-0898). [FN4] RG&E expects that future multi-year opinions of the Commission will resolve electric and gas issues.

The rate decrease would be applied retroactively from July 1, 2000. All customers would receive a one-time credit on their bills for the past period and they would obtain prospectively a base rate reduction of \$2,806,000, annually. The credit and base rate reduction would be allocated proportionately based upon distribution revenues to the service classes (revenues net of gas costs and revenue taxes). Within the classes, the credit would be allocated on a volumetric basis and the base rate reduction would be allocated on a uniform percentage basis, net of gas costs. Both reductions would be implemented on March 1, 2001.

The new rates are designed to provide RG&E an opportunity to earn an 11.0% return on common equity. In the event RG&E achieves a return on equity in excess of 12.5% during any rate year, [FN5] 90% of the excess would be deferred for the benefit of customers. The deferred amount would be used following the rate term to write-down any deferrals for government mandates, catastrophic events, and competition implementation costs (discussed below) that may have accumulated during the rate term, and then any remaining amount would be allocated in accordance with our direction. The company's return on equity would also be subject to adjustment for several incentive programs that are discussed in the sections below.

In one such program, the Mercury Regulatory Replacement Program, RG&E has begun to remove, replace and dispose in an environmentally safe manner all regulators on its system that contain mercury. The Joint Proposal commits the company to eliminate these regulators prior to June 30, 2002. In the event it fails to conclude this work by June 30, 2002, for reasons other than an inability to hire qualified contractors, the 12.5% threshold for sharing 'excess' earnings would be reduced for each rate year in proportion to the number of installations not completed, up to a maximum of 25 basis points.

The Joint Proposal also contains guidelines for cost deferrals. Essentially, only 'prudent and verifiable' costs may be deferred and RG&E is required to file a petition seeking our approval for any deferral and recovery. The Joint Proposal observes that our regulations could be construed as requiring deferral petitions to be filed by the close of a calendar year. [FN6] To avoid multiple unnecessary deferral petitions, the Joint Proposal seeks a waiver of this regulation to permit the company to file its petitions after the close of a rate year. The deferrals specifically addressed in the Joint Proposal include Mandates and Catastrophic Events, Competition Implementation Costs, Cast Iron and Bare Steel Main Replacement, and Gas Delivery Management Systems.

Mandates include governmental action and accounting changes; catastrophic events include natural disasters and states of emergency, as well as events that result in curtailment of gas *101 service. If the company incurs an individual mandate or catastrophic event in excess of \$600,000 in any rate year, RG&E may petition for deferral of the entire amount as defined in the Joint Proposal.

Competition implementation costs, are defined as incremental expenditures incurred in connection with regulatory proceedings, legislation, regulations and orders pertaining to the development of a competitive gas market. If these costs exceed \$300,000 in any rate year, RG&E may petition for deferral of the amount in excess of \$300,000.

Through the end of the rate term (June 30, 2002), RG&E plans to spend at least \$9.5 million to replace cast iron and bare steel mains. In the event it does not achieve this target level of expenditures, the company would defer the revenue requirement impact of the shortfall for future disposition at our discretion.

The Joint Proposal also contains provisions to amortize amounts paid to the company pursuant to a court-approved settlement involving contractor bid-rigging, the accounting treatment for FASB 112 post-employment benefits, the amount required to levelize the rate decrease over the two-year rate term, and the excess reserve amount pertaining to an over-accrual of book depreciation versus theoretical depreciation. RG&E is permitted some flexibility to allocate amounts as it deems appropriate over the rate term; however, the unamortized balance for any particular item remaining at the end of the rate term cannot be greater than the results shown in Appendix B attached to the Joint Proposal.

As to amortizations pertaining to gas delivery management systems, they would be recovered through balancing charges over a four-year period beginning April 1, 2001. If the amount to be amortized is not known by that date, the company would be permitted to set the balancing charges to recover a maximum of \$250,000 annually until the actual amount is determined, at which time, the amortization amount would be adjusted accordingly.

RG&E's implementation costs of the information systems necessary to support the gas delivery management system are estimated in Appendix C of the Joint Proposal. RG&E would be entitled to request deferral of these costs for future recovery and Staff and the company will meet to discuss the calculation of the deferral amount.

Finally, the Joint Proposal does not preclude RG&E from obtaining rate adjustments for it to comply with our orders regarding tax law changes. The Joint Proposal's revenue requirements were based on the tax laws in effect prior to the enactment of the 2000-2001 New York State Budget. The Joint Proposal also does not prevent RG&E from obtaining rate adjustments as necessary to comply with our orders regarding the collection of System Benefits Charges through gas rates. RG&E has reserved its right to contest any future orders on these subjects.

RATE DESIGN

[9-12] The Joint Proposal calls for a series of rate design changes most of which would take effect as of September 1, 2001. They would affect Service Classification (SC) No. 1 Service, SC No. 3 -- Large General Transportation Service, and SC No. 5 -- Small General Transportation Service. Appendix D to the Joint Proposal shows the rates expected for these classes.

With regard to SC No. 1, RG&E will implement changes to the gas adjustment clause consistent with certain 1999 revisions to our regulations (16 NYCRR §270-6.5). The company would also separate the cost of gas (both commodity and capacity) from the distribution (delivery) rates and would state the cost of gas as a separate component on the bill.

Also, the SC No. 1 block rates would be redesigned and the 30,001-100,000 and 100,001-1,000,000 therm rate blocks would be eliminated. These blocks are largely unused due to the migration of many large customers to transportation service (SC No. 3) and their elimination would simplify the rate structure. Under the Joint Proposal, the rates for the remaining therm block rates, other than the initial (0-3 therm) block, would be reduced on a uniform percentage basis net of gas costs to reflect the revenue decrease. The SC No. 1 monthly customer charge would be increased from \$6.90 to ***102** \$12.00, excluding gas costs. [FN7] According to RG&E's marginal cost studies, the monthly customer cost for this class of customers is at least \$21.62 per month.

The SC No. 5 block structure would be redesigned in the same manner as SC No. 1. The remaining therm block rates, other than for the initial (0-3 therm) block, would be reduced on a uniform percentage basis to reflect the revenue requirement decrease and the SC No. 5 customer charge would be increased from \$5.81 to \$12.00 per month.

For SC No. 3, the revenue requirement reduction would be implemented by reducing, on a uniform percentage basis, the 1001-30,000, 30,001-100,000 and 100,001-1,000,000 block rates. The monthly customer charge of \$240.00, which applies to the first

1,000 therms of use and the tail block rate would remain at their current levels.

PROVISIONS PROMOTING COMPETITION

[13-17] The Joint Proposal contains various provisions to help establish a competitive retail gas market. There is the Retail Access **Capacity** Program that would allow RG&E to **release** certain upstream **capacity** to marketers who serve small-volume **customers** in the company's service area. **Capacity releases** pursuant to this program would be adjusted periodically to correspond to the load served by each marketer with the amount of **capacity released**. RG&E could recall its **released capacity** in the event the marketer becomes unqualified to serve or if the **capacity** is needed for system reliability purposes. Marketers would pay maximum tariff or contract rates for the **released capacity**. The cost of storage **assets** would be determined in accordance with the formula contained in Appendix E. **Releases** would generally be for a minimum term of one year.

There is also a **Capacity** Incentive Program consisting of a **Capacity** Cost Incentive, and a **Capacity** Cost Imputation. Pursuant to the **Capacity** Cost Incentive, RG&E and its **customers** would **share** any savings or increased costs between a base level of **capacity** costs and the actual **capacity** costs RG&E achieved. The base costs would reflect the company's current **capacity** commitments. Actual costs would reflect the extent to which RG&E is able to reduce costs through **releases**, restructuring and other portfolio **management** techniques. The **sharing arrangement** would allow RG&E to retain: 15% of total annual savings greater than \$0.5 million and up to \$2.0 million; 50% of savings greater than \$2.0 million up to \$4.0 million; and 15% of savings in excess of \$4.0 million. If capacity costs increase, RG&E would bear: 50% of increased cost over \$0.5 million and up to \$2.5 million; and 15% of the portion of such costs exceeding \$2.5 million. The savings or increased cost sharing would be reflected in the gas adjustment clause.

The Capacity Cost Imputation, would capture for customers the savings derived from short-term (one year or less) transactions, including releases and off-system sales up to a specified level. A total of \$1.1 million would be imputed to the company for the period April 1, 2001 through June 30, 2002 and \$0.5 million per year for the period July 1, 2002 through March 31, 2004. To the extent that RG&E achieves any savings in excess of those levels, customers would receive 95% of them and the company would receive the remainder.

The Joint Proposal contains marketer services provisions that require RG&E to designate a corporate vice-president to be a liaison to the marketers. In addition, Staff will implement a satisfaction survey for marketers and conduct annual surveys

beginning on May 1, 2001 and on May 1, 2002.

The Joint Proposal provides that, if customer migration were to exceed 30% of the small-volume customer market during its term, the parties would meet to discuss possible changes to the PSC Transition Cost Surcharge and consider reducing the allocation of capacity costs to SC No. 1 customers. This provision recognizes that, absent a change, SC No. 1 customers could bear an inordinate share of capacity costs.

CONSUMER PROGRAMS

Pursuant to the Joint Proposal, RG&E would establish a Low-Income Program, a Service Quality Performance Program, a Customer ***103** Competition Education Plan and a Department of Social Services Aggregation Program.

Low-Income Program

[18, 19] RG&E's Low-Income Program would consist of two segments, the Residential Energy Consumer Assistance Program (RECAP) and the Weatherization Grant Program. The RECAP would assist 900 customers, providing them benefits in the form of a \$20 reduction in their monthly budget payments, arrears forgiveness of up to \$250 per year, and household budget and energy efficiency counseling.

The Weatherization Grant Program would provide customers energy efficiency education, and energy efficiency and weatherization services. RG&E would work with two local agencies, Action for a Better Community and Rural Opportunities, to provide these services, and it would designate grant money to enable them to provide weatherization measures for where they are needed the most.

The Low-Income Program would remain in effect at least through June 30, 2002 and would continue thereafter unless it is modified or eliminated by Commission order.

Service Quality Performance Program

[20, 21] The Service Quality Performance Program would apply to RG&E's gas and electric operations. It consists of six measures: Adjusted Bills, PSC Complaint Rate, Estimated Meter Reads, Calls Answered Within 30 Seconds, Appointments Kept,

and Customer Transaction Survey. Each has specific performance levels and penalties for failure to achieve the performance targets. The maximum penalty for each measure is 7 basis points (42 basis points for all). This program would become effective on January 1, 2001 and it would continue until it is modified or eliminated. During the initial period which extends for only six months, from January 1, 2001 through June 30, 2001, each performance indicator would be limited to a maximum of 5 basis points.

Customer Competition Education Plan

[22] The Customer Competition Education Plan would become effective immediately and it would extend through June 30, 2002. It includes an outreach and education campaign to promote customer awareness and understanding of retail choice. The company is required to survey customers and measure the achievement of certain target levels of awareness and understanding. RG&E will also hold a 'utility/marketer customer education forum' at least once per year to announce its plans for customer education and marketing in the coming year. The annual budget for this program would be \$200,000.

Department of Social Services Aggregation

[23, 24] RG&E would implement a Department of Social Services Aggregation Program to allow recipients of State-provided recurring temporary assistance to enroll in the gas retail access program. This program would be for clients who receive home energy allowances through restricted payments made directly to gas suppliers. It is not intended that the company or other customers subsidize the development or ongoing costs to operate this program. RG&E would work with interested counties within its service area to design and implement a mutually acceptable program for these customers to participate in retail access.

MISCELLANEOUS PROVISIONS

The Joint Proposal contains various standard provisions that: (1) allow the parties to petition us if they are unable to resolve differences among themselves; 2) allow parties to petition us should material and unforeseen events arise and recognize that, pursuant to our statutory responsibilities, we reserve authority to act on the level of RG&E's rates if unforeseen circumstances should render the company's rate of return on investment unreasonable, inadequate or excessive for the provision of safe and adequate service; (3) recognize that the Joint Proposal is the product of negotiations and that it cannot be cited or relied upon as precedent for any matters other than those specifically addressed within it; (4) state that the *104 Joint

Proposal controls to the extent there may be any conflict between its provisions and those of the September 1999 or the June 2000 proposals; (5) permit parties to withdraw from the Joint Proposal and pursue litigation if its terms are modified; and (6) recognize RG&E's concessions and commitments.

POSITIONS OF THE PARTIES

Staff and RG&E observe that our Gas Policy Statement sets forth six principal issues that local distribution companies (LDCs) are to address in their compliance proposals:

- (1) A strategy to hold new capacity contracts to a minimum;
- (2) A quantification of potential stranded costs and a plan to mitigate and manage them;
- (3) A long term rate plan with a goal of reducing or freezing rates;
- (4) A plan to further unbundle rates which would:
 - (i) separate distribution and gas purchase (upstream) costs;
 - (ii) separately identify distribution cost elements;
 - (iii) identify changes which would promote retail competition;
 - (iv) propose other rate design changes, if appropriate;
- (5) A plan to enhance consumer education programs and facilitate customer participation; and,
- (6) The possibility of a more aggressive role for LDCs in facilitating the move to a competitive market. [FN8]

According to the company and Staff, the Joint Proposal, together with the September 1999 and the June 2000 orders, address all of the provisions of the Gas Policy Statement.

With regard to items 1 and 2 above, they maintain that the Capacity Incentive Program provides appropriate penalties for poor performance and rewards for superior performance for the company to achieve cost savings, while at the same time preserving the system's integrity. They state that the Retail Access Capacity Program helps to mitigate capacity costs that might otherwise be stranded by customer migration.

The Joint Proposal, according to Staff and RG&E, addresses the objective to hold down rates (item 3) by implementing a \$2.8 million annual rate reduction at a time when the commodity cost of natural gas is high. This comes after a six-year period during which RG&E's base rates have remained stable.

RG&E asserts it is continuing to restructure gas rates (item 4) with the rate design provisions in the Joint Proposal, which are to become effective September 1, 2001. They require changes to the gas adjustment clause, the elimination of obsolete rate blocks, and an increase in the monthly minimum charge. These changes, the company notes, produce a clearly identified delivery or distribution rate, a simplified rate structure, and a more equitable allocation of revenue responsibility between large and small customers.

The Joint Proposal, Staff and RG&E explain, furthers the objective of educating customers and facilitating their participation in the competitive market (item 5). The Customer Competition Education Plan will increase customer awareness and understanding of competitive choice, particularly for residential and small commercial customers.

Staff and RG&E reason that, individually and as a whole, the steps taken in the Joint Proposal aggressively move us forward to a competitive market (item 6). Thus, they conclude, the Joint Proposal fully complies with the Gas Policy Statement and furthers our vision of an emerging competitive market for natural gas.

RG&E goes a step further and maintains that the Joint Proposal exceeds the requirements of the Gas Policy Statement by implementating a low-income customer

assistance program and a service quality incentive mechanism with six measures of performance and penalties for any failure to meet the standards. RG&E also points to its liaison to facilitate communications between marketers and the company, and its commitment to replace all mercury regulators on its system and to replace cast iron and bare *105 steel mains. Lastly, the company points to the retail access program for recipients of state-provided temporary assistance.

Energetix also urges us to approve the Joint Proposal, believing it represents an equitable resolution of many difficult issues posed by the Gas Policy Statement.

CPB considers the Joint Proposal to be generally reasonable with the exception of some of its rate design provisions. Specifically, CPB objects to increasing the residential customer minimum charge from \$5.81 to \$12 per month. CPB considers the annual increase in the minimum charge to be excessive and detrimental to consumers. CPB refuses to accept the results of RG&E's marginal cost study for this class of customers. It believes the study improperly included a large amount of distribution and other costs, and that it is fundamentally flawed.

CPB contends that RG&E's customer cost calculation should not be used because we did not approve it and because customer impact, and other public policy, considerations can be cited to counter it. For example, CPB observes that 8,277 cooking-only customers consume between 10 and 20 therms per month and they would receive bill increases of between 25% and 45.3%. CPB estimates that approximately 1,600 such customers exist who may not benefit from the low-income plan included in the Joint Proposal.

CPB points out that a \$12 minimum charge would exceed the average New York State minimum charge by approximately 39.2%. It suggests that the minimum charge only be increased to \$7.00 or about 20.5%, and it believes that all such increases should be generally constrained to the state average of approximately \$8.62 per month.

Mr. Lawrence W. Owens and Mr. Charles A. Straka also oppose the proposed minimum charges. They contend that an increase to \$12.00 is too large and it would disproportionately impact low-use customers. One would limit the charge to \$9.00, the other would phase it in over four years.

According to Staff, there is ample justification to increase the minimum charges of SC Nos. 1 and 5 and to decrease the next three rate blocks on a revenue neutral basis. It states this will result in more customer-related costs being recovered in

the minimum charge and less in the block rates. Staff accepts the cost studies that show a minimum cost to serve residential customers of \$21.62 per month. Even if gas mains costs were removed from the minimum cost to serve, Staff still calculates a resulting minimum charge of about \$15 per month.

Pointing to the fully embedded cost of service studies for RG&E, Staff observes that low-use residential customers who do not use gas for space heating purposes provide a low rate of return and that they are cross-subsidized by higher-use customers. An increase to \$12, Staff argues, would address these low rate of return and cross-subsidy issues. Staff also maintains that now is the time to address the comparatively low minimum charges in SC Nos. 1 and 5 because the customer impacts will be partial offset by the overall revenue decrease.

For comparison purposes, Staff points out that the minimum charges for National Fuel Distribution Corporation, Niagara Mohawk Power Corporation, and New York State Electric and Gas Corporation are consistent with the Joint Proposal at \$12.92, \$14.55 and \$14.00, respectively, exclusive of gas costs.

DISCUSSION

[25-30] CPB's claim that a \$12.00 minimum charge is excessive and is not well supported by RG&E's marginal cost study (which shows a \$21.62 cost to serve) is itself a dubious assertion. We note that even if the allocated portion of gas mains is removed from the calculation, the resulting minimum cost would still be about \$15 per month, which largely consists of direct costs for such items as the customer's meter, service line and billing. Thus, we are not convinced by CPB that the proposed \$12.00 minimum charge is excessive or otherwise exceeds the minimum cost of providing service to a customer. Further, as Staff points out, other major gas utilities in western New York, have minimum charges that exceed \$12.00 per month. Finally, the time to reduce the existing cross-subsidy is best when an overall revenue decrease is being implemented which can mitigate *106 the impacts of the increase in the minimum charge for many customers. For these reasons, we will approve the minimum charge as set forth in the Joint Proposal with one exception.

We will freeze the monthly minimum charge at \$5.81 (exclusive of gas costs) for HEAP eligible non-heating gas customers on RG&E's system. We believe that the relatively large increase in the minimum charge for these customers would create too much of a rate increase for these low-usage customers.

We note that the Joint Proposal calls for changes in the rate design to become effective September 1, 2001. However, there are no SC Nos. 1 and 5 customers whose

usage is large enough to qualify for rates in the last two rate blocks of these classifications. Therefore, we direct RG&E to eliminate these two rate blocks in its March 2001 compliance rate filing.

With respect to the Low-Income Program, the Joint Proposal sets forth two program components: RECAP and a Weatherization Grant Program. For the RECAP portion, the Joint Proposal would authorize a surcharge to recoup the cost of the program. Instead, we direct that the RECAP cost be netted against the gas costs and revenues that are reconciled through the gas adjustment clause for sales customers and through the comprehensive and firm transportation rate adjustment for SC No. 5 and SC No. 3 customers, respectively. Also, the Weatherization Grant Program could be supplanted by our recently-enhanced System Benefits Charge program. We hereby direct RG&E to work with our Staff and NYSERDA to coordinate the SBC-funded energy efficiency/weatherization efforts with the RECAP program throughout RG&E's territory. Thus, we do not authorize the establishment of this program and will not allow recovery of the costs associated with it. RG&E should also work with NYSERDA in the implementation of the Department of Social Services Aggregation Program.

The Joint Proposal would also establish a \$200,000 Customer Competition Education Plan. Similar to our treatment of the Weatherization Grant Program, we instead direct RG&E to work with our Staff to implement such a program in RG&E's territory, funded by a portion of SBC funds that have been allocated for public awareness programs.

With respect to the miscellaneous provision stating that the Joint Proposal controls to the extent there may be any conflicts with the provisions of the September 1999 and June 2000 proposals, we emphasize that the instant order is the controlling document and not the Joint Proposal.

Turning to the remaining terms of the Joint Proposal, we find that they are reasonable and serve our public policy objectives as expressed in the Gas Policy Statement. The comments we received supporting the Joint Proposal properly note that it and our previous orders in this case serve to create an environment that supports the development of natural gas retail access. Thus, we find that the Joint Proposal is in the public interest.

Among its most salient features are the following commitments made by RG&E: reduced gas distribution rates; imputation of upstream capacity cost savings to benefit customers; a capacity cost incentive mechanism with a penalty provision; customer service quality standards with penalty provisions; continuation of the cast iron and bare steel main replacement program; replacement and disposal of all mercury

regulators in an environmentally safe manner; and cooperative efforts with local municipalities to facilitate retail choice for Department of Social Services clients.

We expect that the rate reductions (which total approximately \$3.0 million, instead of \$2.8 million proposed) and the assignment of upstream capacity will benefit customers by lowering gas bills and enhancing competition. Further, as interest among marketers to serve in RG&E's service area develops, the benefits of greater market competition should become readily apparent to ratepayers.

It is ordered:

1. The terms and conditions set forth in the 'Joint Proposal Pertaining to Rochester Gas and Electric Corporation's Natural Gas Rates and Restructuring Program' (Joint Proposal) filed January 25, 2001 and appended as an attachment to this order, are adopted, as modified above in the text of this order, and are incorporated *107 as part of this order.

2. Rochester Gas and Electric Corporation shall file on not less than one day's notice, to become effective on March 1, 2001, the tariff changes necessary to implement the rate changes in accordance with the terms of the Joint Proposal filed on January 25, 2001, as modified above in the text of this order, and shall serve copies of its tariff filing upon all parties to the proceeding. Any comments on the filing must be received at the Commission's offices within ten days of service of the proposed amendments. The amendments shall not become effective on a permanent basis until approved by the Commission. The requirement of \$66(12)(b) of the Public Service Law as to newspaper publication of these amendments is waived.

3. This proceeding is continued.

JOINT PROPOSAL PERTAINING TO ROCHESTER GAS AND ELECTRIC ECTRIC CORPORATION'S
NATURAL GAS RATES AND RESTRUCTURING PROGRAM

INTRODUCTION

Parties

This Joint Proposal pertaining to Rochester Gas and Electric Corporation's Natural Gas Rates and Restructuring Program ('Joint Proposal,' 'Proposal ') embodies the

agreement, entered into this 25th day of January 2001, by and among the Staff of the Department of Public Service ('Staff'), Rochester Gas and Electric Corporation ('RG&E,' the 'Company'), Energetix, Inc. ('Energetix '), Amerada Hess Corporation ('Amerada Hess'), and Dominion Transmission, Inc. ('Dominion'), collectively referred to as the 'Parties.'

Subject

This Joint Proposal, in conjunction with two previously approved documents, is intended to address, in a comprehensive Rate and Restructuring Program (the 'RRP'), all issues pertaining to the rates for service to be charged by RG&E during the term hereof, together with the on-going restructuring of the Company's natural gas business, as contemplated in the Public Service Commission's ('Commission's') Policy Statement Concerning the Future of the Natural Gas Industry in New York State and Order Terminating Capacity Assignment, issued November 3, 1998 in Cases 93-G-0932 [FN1] and 97-G-1380 [FN2] (the 'Policy Statement') and other Orders issued in these and other Commission proceedings. [FN3]

Background

Since mid-1998, RG&E, Staff, and other parties have engaged in negotiations regarding the Company's rates and restructuring. These negotiations have resulted in two previous agreements among the Company, Staff and several of the current Parties. The first, a Proposal for Capacity Release Revenue Imputation and Capacity Cost Mitigation Issues and Framework for Resuming Settlement Negotiations ('September 1999 Proposal'), addressed the following issues: a capacity release revenue imputation; capacity cost mitigation measures; a timetable for a public filing and resumption of negotiations; and improvement of RG&E's retail access program. The September 1999 Proposal was approved by the Commission in an Order Approving Petition issued September 30, 1999 in the instant proceeding ('September 1999 Order').

Pursuant to the September 1999 Proposal and the September 1999 Order, RG&E, on January 28, 2000, made a filing (the 'January 2000 Filing') addressing various issues pertaining to the Company's natural gas business, including proposals for restructuring that business and facilitating migration from fully bundled sales service to retail service provided by natural gas marketers. Certain issues presented by the January 2000 Filing were resolved in a second agreement, the Settlement Agreement Pertaining to Certain Elements of Natural Gas Retail Access Program entered into among RG&E, Staff and certain other parties on June 14, 2000 (the 'June 2000 Settlement').

The June 2000 Settlement addressed the following issues: providing a backout credit to *108 be paid to marketers serving retail customers; eliminating the backout credit for certain market concentrations; providing a mechanism to keep the Company whole for differences between the backout credit and actual cost savings realized from migration; introducing a single-retailer model for natural gas service similar to that in effect for electric retail access; providing a process for managing gas deliveries into the RG&E system; providing for a specified communications protocol between marketers and the Company; and providing for continued reductions in capacity costs charged to customers.

The June 2000 Settlement was approved by the Commission in an Order Adopting Terms of Settlement Agreement issued July 31, 2000 in this proceeding ('July 2000 Order'). Following approval, RG&E has proceeded to implement the provisions of the June 2000 Settlement.

The capacity cost reductions imputed pursuant to the June 2000 Settlement were to have expired as of October 31, 2000. [FN4] RG&E agreed to extend the imputation through March 31, 2001 and, on October 18, 2000, filed a proposed amendment to the June 2000 Settlement to provide for such extension. By Order Concerning Extension of Capacity Cost Imputation issued December 5, 2000 in the instant proceeding, the Commission approved the extension and ordered RG&E to flow through the impact of the imputation through the Gas Cost Adjustment ('GCA ') to coincide with the December 2000 through March 2001 period.

This Joint Proposal is intended to resolve all outstanding issues identified by the parties and not resolved in either the September 1999 Proposal or the June 2000 Settlement, as approved by the Commission.

Negotiations

Negotiations regarding the issues addressed herein began on February 29, 2000 and were carried out through a combination of meetings, conference calls, and discussions among members of subject-specific Working Groups. Those negotiations were conducted pursuant to the Commission's regulations governing settlements (16 NYCRR § 3.9). Hon. Eleanor Stein has served as the Settlement Administrative Law Judge and Hon. Walter T. Moynihan has served as the Litigation Administrative Law Judge.

At one time or another, representatives of the following parties participated in the negotiation process: Staff, RG&E, the Consumer Protection Board, Multiple Intervenors, Agway Energy Services, Inc., All Energy Marketing Company LLC, Amerada Hess Corporation, ANR Pipeline Company, Dominion Transmission, Inc., Dynegy Marketing and Trade, Empire State Pipeline, Energetix, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation, North American Energy, Inc., Shell Energy Services, LLC, Charles A. Straka, and TXU Energy Services. Drafts of this Proposal were circulated to all current participants in the negotiations.

RATE AND RESTRUCTURING PROGRAM

The Parties agree among themselves on the following resolution of issues and jointly present and propose such resolution to the Commission for approval.

Term

1. Except as expressly provided otherwise herein, the RRP shall be effective upon approval by the Commission and shall continue in effect until March 31, 2004. Such period is referred to herein as the 'RRP Term.' The rates established pursuant to the RRP shall apply to the period July 1, 2000 through June 30, 2002, which period is designated herein as the 'Rate Term.' During the Rate Term, each of the two periods commencing July 1 of one calendar year and terminating on June 30 of the following calendar year shall be considered a 'Rate Year.' The expiration of the Rate Term and/or the RRP Term shall not diminish the right of RG&E to recover prudently incurred costs.

Revenue Requirements

2. Except as expressly provided otherwise herein, natural gas revenue requirements, for ***109** the purpose of setting base rates for the period beginning July 1, 2000, shall be decreased a total of \$2,806,000 from the levels in effect on June 30, 2000. This rate level is based on a return on equity ('ROE') of 11.00 percent, which shall be deemed to be the allowed ROE for all purposes pertaining to this Joint Proposal and the RRP. This rate level recognizes a levelization adjustment intended to allow base rates to remain unchanged over the Rate Term. An Income Statement showing the foregoing decrease for the Rate Term is attached hereto as Appendix A.

3. Base rates shall be adjusted effective March 1, 2001 to reflect the revenue requirements decrease referred to in paragraph 2. Because the current base rates

that will be in effect through February 28, 2001 are higher than those proposed herein, the total reduction that would have been experienced by customers during the period July 1, 2000 through February 28, 2001, had the reduced rates been in effect, shall be passed back to all customers through a temporary credit applied to rates, on a volumetric basis, during the month of March 2001. The method for calculating the credit is provided in Appendix D. Immediately prior to the implementation of the credit, the calculation will be updated for actual sales volumes only, to the extent that actual volumes are available at the time. Forecast data will be utilized for the final month of the applicable period. The Parties have contemplated an implementation date of March 1, 2001 for the RRP. In the event that implementation occurs on a date other than March 1, 2001, the computation of the credit shall be adjusted to reflect the actual implementation date. In the event that implementation occurs on a date other than March 1, 2001 and such difference in timing affects elements of this Joint Proposal other than computation of the credit, the Parties shall reconvene to address such circumstances. To the extent that the amount actually passed back through this credit differs from the intended amount, the difference will be deferred for future disposition at the discretion of the Commission.

Deferrals

4. No cost referenced herein may be considered for recovery, true-up or deferral unless it is prudent and verifiable. Wherever in this Proposal reference is made to deferral of any amount, such reference shall be construed as meaning that RG&E may defer any such prudently incurred amount and shall be entitled to recover that amount, either as specifically provided in such reference or, if no specific method of recovery is identified, over an appropriate amortization period to be determined by the Commission following the Rate Term. Without otherwise limiting such entitlement to recovery, RG&E shall file with the Commission a petition seeking approval for deferral and recovery. Where deferral pertains to a period other than a calendar year (e.g., a Rate Year), the Commission's regulations [FN5] that might be construed as requiring all such petitions to be filed by the close of a calendar year should not apply. The Company shall be permitted to file such petition at the conclusion of the relevant Rate Year period. Accordingly, approval of this Proposal by the Commission shall be construed as granting a waiver of the regulations to the extent required to permit such Rate Year filings.

Amortizations

5. Appendix B shows the items and amounts thereof that will be deemed to have been amortized during the Rate Term, with the exception of amounts for gas delivery management systems, [FN6] which shall be in addition to the amounts shown. RG&E

shall be permitted to record amortizations and unamortized balances as it deems appropriate over the Rate Term provided, however, that at the conclusion of the Rate Term, any unamortized balance for a particular item shall not be greater than it would have been had the amortization been recovered as shown in Appendix B. For purposes of computing regulatory earnings, the levels of amortization expenses shall be as indicated in Appendix B, with the exception of amounts for gas delivery management systems, which shall be in addition to the amounts shown.

6. The amounts amortized for deferred gas delivery management systems costs will track amounts actually collected through balancing *110 charges for that purpose. Charges will be set with the intent of fully recovering such costs over a four-year period beginning April 1, 2001. If the amount to be amortized is not known as of April 1, 2001, the Company shall be entitled to set balancing charges so as to recover \$250,000 annually until the actual amount is determined, at which time the amortization amount shall be adjusted accordingly. Without limiting the total amount that may be deferred and recovered, the annual recovery shall not exceed \$250,000 during each Rate Year of the Rate Term.

'Excess' Earnings

7. In the event that RG&E achieves a return on common equity in excess of 12.5 percent, in any Rate Year covered in this Proposal, 90 percent of the excess over that level shall be deferred for the benefit of customers. Actual reported earnings for measuring ROE shall exclude any penalties paid or incentives earned by RG&E pursuant to this Proposal. Any amounts deferred pursuant to this paragraph 7 shall be used following the Rate Term first to write down deferrals for Mandates, Catastrophic Events and Competition Implementation Costs, if any, accumulated during the Rate Term. The Commission shall determine the disposition of any remaining amount. RG&E shall file its computation of regulatory earnings and any excess earnings deferred with the Commission not later than the September 30th following the end of each Rate Year.

8. In order to determine the common equity balance, the Company shall use actual book common equity allocated to the gas department on the basis of the Company's relative gas earnings base. The maximum amount of common equity used to determine ROE sharing, however, shall be capped at \$155,000,000.

Bases for Change in Rates

Taxes

9. This Proposal shall not prevent the Company from adjusting rates as necessary to comply with Commission orders regarding tax law changes. [FN7] The revenue requirements contained in this RRP were determined using tax laws in effect prior to the enactment of the 2000-2001 New York State Budget, which included certain provisions affecting the taxation of public utilities. As a result, the revenue requirements do not reflect the tax law changes referred to in Case 00-M-1556. The Company does not hereby forfeit its right to contest any such orders should that become necessary.

System Benefits Charge Costs

10. This Proposal shall not prevent the Company from adjusting rates as necessary to comply with Commission orders regarding collection of System Benefits Charges through gas rates (e.g., as might result for electric rates from the September 29, 2000 Staff Proposal for the Extension, with Modifications, of Systems Benefits Charge-Funded Public Benefit Programs in Case 94-E-0952). [FN8] The Company does not hereby forfeit its right to contest any such orders should that become necessary.

Gas Delivery Management Systems

11. RG&E shall be entitled to defer for future recovery consistent with paragraphs 4 and 6 all incremental costs, incurred during the Rate Term, related to information systems necessary to implement the gas delivery management programs provided for in the June 2000 Settlement. The required functionality for these systems is described in Appendix C. Prior to filing for deferral of such amounts, Staff and the Company will meet to discuss the calculation of the proposed deferral amount and the methods used for identification of incremental costs. For the purposes of this paragraph 11, incremental costs will relate solely to the development and implementation of new gas delivery management systems (the 'Project'). Such costs will exclude straight-time payroll and benefits for existing RG&E employees, but will include costs not anticipated in the revenue requirements analysis adopted for this Joint Proposal, such as: new software and hardware and upgrades required solely for the Project; payroll and benefits for additional employees hired *111 from outside the Company solely for the purposes of the Project; payroll and benefits for the additional employees hired from outside the Company to replace those assigned to the Project; overtime payroll for existing employees working on the Project in excess of 8.6 percent of straight time payroll for those employees; costs (including fees and expenses) related to consultants or contractors required for the Project; and, if travel is required for the Project, travel expenses for RG&E employees.

Mandates and Catastrophic Events

12. In the event that, after the date upon which this Proposal is executed by the Company and on or before June 30, 2002, one or more Mandates is implemented or one or more Catastrophic Events occurs and, during any Rate Year covered by this RRP, the incremental cost impact of any individual Mandate or any individual Catastrophic Event exceeds \$600,000 in any Rate Year, RG&E shall be entitled to defer the entire amount attributable to such Mandates and Catastrophic Events. Amounts so deferred shall be recovered from customers after the Rate Term. For purposes of this document:

(a) A 'Mandate' shall mean (i) any governmental action, including changes in laws and regulations (including tax laws and regulations not provided for elsewhere in this document) and orders of regulatory and other agencies which result in cost changes, and (ii) any changes in accounting required by generally accepted accounting principles. In the event that any such Mandate consists of actions in response to an asserted failure by the Company to conform to valid legal requirements, the Company shall have the burden of showing that its conduct which gave rise to such action was consistent with the best interests of customers.

(b) A 'Catastrophic Event' shall mean an event that triggers the designation of part of the Company's service territory as a disaster area, as being under a state of emergency or that results in curtailment of gas service to any portion of RG&E's customers.

Competition Implementation Costs

13. RG&E shall be entitled to defer incremental Competition Implementation Costs in excess of \$300,000 in any one Rate Year. Amounts so deferred shall be recovered from customers after the Rate Term. The Parties specifically note that this Proposal is not intended to determine the mechanism for recovery of these costs or the degree to which they are collected from one set of customers or another. For purposes of this Proposal, 'Competition Implementation Costs' shall mean all incremental expenditures incurred by RG&E during the Rate Term in connection with all regulatory proceedings, legislation, regulations and orders pertaining to the development of a competitive market for natural gas service.

Rate Design, Generally

14. The rate design changes set forth in paragraphs 15 through 25 hereof shall be made to Service Classification ('SC') No. 1 -- General Service, SC No. 3 -- Large General Service-Firm Transportation and SC No. 5 -- Small General Service-Comprehensive Transportation, and shall become effective on September 1, 2001, unless expressly provided otherwise. The rates resulting from this Proposal and a comparison between the bills resulting from those rates and bills using current rates are contained in Appendix D.

Service Classification No. 1

Implementation of New Gas Cost Adjustment Regulations

15. The Company shall implement certain changes to the operation of the GCA, identified herein, consistent with the Commission's Memorandum and Resolution Revising 16 NYCRR Section 270.55, issued on April 13, 1999 ('1999 Memorandum '). Pursuant to these regulations, the Company will roll out the base cost of gas, currently at \$0.358 per therm plus losses at 1.85 percent, from all the rate levels for SC No. 1. This will completely separate the cost of gas (commodity and capacity) from distribution, or delivery rates. The cost of gas will be identified as a separate component on the bill *112 and collected along with other GCA elements beginning on or about September 1, 2001.

16. The Company shall also adopt the following GCA changes provided for in the 1999 Memorandum: (i) inclusion of risk management costs in the GCA; (ii) calculation of the fixed-cost component of the average cost of gas on the basis of weather-normalized volumes; (iii) calculation of the commodity component of the average cost of gas on the basis of estimated volumes for the month in which the GCA will be effective; (iv) reconciliation of the GCA at interim periods during the GCA reconciliation year, in addition to the annual reconciliation; and (v) filing a revised GCA within five days of the effective date of an initial GCA filing when the replacement of estimated prices with actual prices results in a change in the average cost of gas of more than five percent.

Redesign of Block Rates

17. The 3 0,001-100,000 and 100,001-1,000,000 therm rate blocks shall be eliminated

from SC No. 1.

Revenue Reduction

18. The remaining therm block rates in SC No. 1, other than the 0-3 therm block rate, shall be reduced on a uniform percentage basis net of gas costs to reflect the decrease in revenue requirements.

Customer Charge

19. With gas costs rolled out of rates, the monthly customer charge for SC No. 1 service shall be increased from \$5.81 per month to \$12 for the 0-3 therm rate block. To reflect this change, corresponding revenue neutral adjustments shall be made to decrease the 4-100, 101-500 and 501-1000 therm rate blocks.

Service Classification No. 3

Revenue Reduction

20. The 1001-30,000, 30,001-100,000 and 100,001-1,000,000 block rates in SC No. 3 shall be reduced on a uniform percentage basis to reflect the decrease in revenue requirements.

Customer Charge

21. The monthly charge for SC No. 3 service, which applies to the first 1,000 therms of use, shall remain at the current level of \$240.

Service Classification No. 5

Redesign of Block Rates

22. The changes made to the block structure of SC No. 1 shall also be made to the block structure of SC No. 5.

Revenue Reduction

23. The remaining therm block rates in SC No. 5, other than the 0-3 therm block rate, shall be reduced on a uniform percentage basis to reflect the decrease in revenue requirements.

Customer Charge

24. The customer charge for SC No. 5 service shall be increased from \$5.81 per month to \$12 for the 0-3 therm rate block, with corresponding revenue neutral adjustments made to decrease the 4-100, 101-500 and 501-1000 therm rate blocks. After these changes, the customer charge and block rates for SC Nos. 1 and 5 shall be the same.

Factor of Adjustment

25. The factor of adjustment used to calculate gas costs shall be 1.0185.

Transition Costs

26. If migration is expected to exceed 30 percent of the Small-Volume Customer market at any time during the RRP Term, the Parties shall meet to discuss the PSC Transition Cost Surcharge with a view to considering changes in that mechanism which would reduce the allocation of capacity costs to SC No. 1 customers. As used herein, the term 'Small-Volume Customer' ***113** refers to service points eligible to be served under SC No. 5 of the Company's gas distribution tariff, PSC No. 12. The PSC Transition Cost Surcharge is described in Rule D of Appendix A of the Company's gas distribution tariff, PSC No. 12.

Retail Access Capacity Program

27. The Company shall be entitled to implement the Retail Access Capacity Program ('Capacity Program') contained in Appendix E to this Proposal. The Capacity Program

would commence upon implementation of Citygate Swing Customer service offered by Dominion Transmission, Inc. for marketers serving SC No. 5 customers, which is anticipated prior to the 2001-2002 heating season, as provided for in the June 2000 Settlement as approved by the July 2000 Order. [FN9] The Capacity Program will continue at least through March 31, 2004, as described in Appendix E.

Capacity Incentive Program

28. The Company shall implement the Capacity Incentive Program ('CIP'), consisting of two principal elements, a Capacity Cost Incentive and a Capacity Cost Imputation, as contained in Appendix F to this Proposal. The timing of implementation, duration and reporting requirements associated with the CIP shall be as identified in Appendix F. The Parties agree that the relinquishment of capacity contracts upstream of Dawn and Southpoint will result in additional market area purchases for the purpose of serving retail load remaining on RG&E's system. Further, the Parties agree that implementation of this CIP addresses all issues based on facts known to Staff related to the level of the Company's capacity costs.

Low-Income Program

29. The Company will implement the Low-Income Program ('LIP') described in Appendix G to this Proposal.

a. The Residential Energy Consumer Assistance Program ('RECAP') component of the LIP is intended to serve 900 customers. It will provide each participating customer benefits in the form of a \$20 reduction in monthly payments, arrears forgiveness of no more than \$250 per year, and household budget and energy efficiency counseling. Administrative costs related to this component will be capped at 20 percent of the sum of counseling costs and the arrears forgiveness and budget reduction amounts provided to customers. The Weatherization Grant Program segment of the LIP will provide benefits to participants in the form of energy efficiency education and energy efficiency and weatherization services. The budget for the Weatherization Grant Program will be \$100,000 per quarter, including \$3,000 per quarter for RG&E administrative costs. For the purposes of cost recovery during the Rate Term, total LIP costs will be calculated according to the model presented in Schedule 1 to Appendix G using actual participation in the program.

b. Total LIP costs will be allocated between large-volume transportation customers (those currently taking service under SC No. 3 of PSC No. 11) and all other customers on the basis of total margins received from each of the two groups. Within

each of these groups, costs will be recovered through a surcharge on a uniform volumetric basis. The surcharge will be shown as a line item on the GCA statement, the comprehensive transportation rate adjustment statement and the firm transportation rate adjustment statement, applicable to PSC No. 11 and PSC No. 12 as appropriate. Amounts collected through the surcharge will be reconciled to total LIP costs once per year. Any undercollection or over-collection will be recovered or passed back, as the case may be, in the following year. The surcharge will commence July 1, 2001, at a level designed to produce annual revenues of \$811,000.

c. The LIP will be operated as described in Appendix G at least through June 30, 2002. Thereafter, the LIP shall continue in effect and be operated as described in Appendix G unless modified or eliminated by the Commission. The Company shall be ***114** entitled to petition the Commission to modify or eliminate the LIP effective after June 30, 2002. If the Commission fails to act upon the petition within six months from the date of filing, the Company shall have the right, without further authorization, to adjust LIP cost recovery to fully collect administrative costs after that time. To the extent that the adjusted amounts exceed the 20 percent cap on administrative cost recovery they will be subject to refund if found unreasonable after Commission review.

Service Quality Performance Program

30. The Company shall implement the Service Quality Performance Program ('SQPP ') contained in Appendix H to this Proposal. It shall apply to both gas and electric operations. Such program shall be effective beginning January 1, 2001, and shall continue until modified or eliminated by the Commission. The SQPP will operate as described in Appendix H at least through June 30, 2002. The Parties shall be entitled to petition the Commission to modify or eliminate the SQPP after that date. The first SQPP period will be the six-month period beginning January 1, 2001 and ending June 30, 2001. Each performance indicator will be worth a maximum of 5 basis points during this period. Subsequent SQPP periods will begin each July 1 and end each subsequent June 30. If any penalties are incurred for such periods, the penalty levels will be the full amounts listed in Appendix H. The reporting and auditing requirements associated with the SQPP shall be as identified in Appendix H.

Customer Competition Education Plan

31. The Company shall implement the Customer Competition Education Plan ('CCEP ') contained in Appendix I to this Proposal. Such program shall be effective upon approval of this Proposal by the Commission and shall continue through June 30, 2002. The budget for the CCEP and the reporting requirements associated therewith

shall be as identified in Appendix 1.

Marketer Services

32. RG&E will designate a vice-president level representative to serve as a liaison between marketers and the Company. Marketers will be provided with the representative's telephone number and the representative will be available directly to marketers.

33. Staff will implement an objective marketer satisfaction survey with input by interested Parties. The survey instrument would serve as an evaluation mechanism of the marketers' level of satisfaction as to the quality of services delivered by and interactions with the Company. After the first year the survey instrument is employed, it may be revisited to incorporate any modifications, additions or deletions agreed to by the Parties. The annual survey would start on May 1, 2001 and May 1, 2002.

Mercury Regulator Replacement Program

34. RG&E has begun a Mercury Regulator Replacement Program ('MRRP') whereby the Company plans to remove, replace, and dispose of, in an environmentally safe manner, all regulators on its system that contain mercury. The Company shall provide the Office of Gas and Water, Safety Section, of the Staff with semi-annual progress reports regarding this program. Such reports are contemplated to be filed in March and September of each year of the remaining RRP Term and thereafter until the MRRP is complete. This replacement work is expected to be completed by June 30, 2002. If the Company determines that it will be unable to remove and replace all of these regulators during this period, it shall report this fact, no later than April 30, 2002, to Staff and provide for Staffs review alternative plans intended to complete the replacement program as soon as practicable. If the replacement work is not complete by June 30, 2002, and the cause of the delay is other than an inability to hire contractors qualified to execute the replacement work in a safe and efficient manner, the 12.5 percent threshold for sharing excess earnings, described in paragraph 7, will be reduced. The reduction shall be computed according to the following formula:

$$*115 \text{ R} = 25 \text{ basis points} \cdot ((20,000 - N) / 20,000),$$

where:

R = the reduction; and

N = the number of replacements completed during the Rate Term.

Cast Iron and Bare Steel Main Replacement

35. The Company plans to expend at least \$9.5 million on cast iron and bare steel main replacement projects through the end of the Rate Term. If the Company does not achieve these targeted amounts, it will defer the revenue requirement effect, with interest, of the difference for future disposition at the discretion of the Commission. Any shortfall will be deemed to have occurred on an average monthly basis throughout the Rate Term.

Department of Social Services Aggregation

36. RG&E agrees to implement an economically viable Department of Social Services ('DSS') Aggregation Program. Any assessment of viability will be provided to Staff. The Company expects to be able to provide such assessment by July 30, 2001. For purposes of this Proposal, a DSS Aggregation Program is defined as a program that allows recipients of New York State-provided recurring temporary assistance to enroll in the gas retail access program. Such DSS Aggregation Program shall be directed toward clients who receive a home energy allowance through a restricted payment made directly to the gas supplier. Implementation shall be preceded by an agreement between RG&E and any other entity necessary for implementation regarding the specific elements of the DSS Aggregation Program and the level of funding required from that entity. Nothing in this Proposal shall be construed as requiring RG&E or its customers to subsidize the development or ongoing operation of such a program. The Company agrees to work with interested counties within its service territory to design and implement a mutually acceptable program.

Dispute Resolution

37. In the event of any disagreement over the interpretation of this Proposal or the implementation of any of the provisions hereof, which cannot be resolved informally among the Parties, such disagreement shall be resolved in the following manner unless otherwise provided herein: The Parties shall promptly convene a conference and in good faith shall attempt to resolve such disagreement. If any such

disagreement cannot be resolved by the Parties, any Party may petition the Commission for relief on a disputed matter.

Petition for Relief

38. In the event that a condition occurs or is likely to occur, that any Party to this Proposal believes (a) would have a material impact on this Proposal, (b) has not been adequately addressed by the provisions hereof, and, (c) if known at the time this Proposal was negotiated, would likely have been addressed herein, such Party shall have the right to petition the Commission for review of the operation of this Proposal and appropriate remedial action.

39. Any Party seeking review pursuant to the preceding paragraph shall have the burden of showing to the Commission's satisfaction that continued operation of the Proposal as to the specific basis for that Party's petition is unjust or unreasonable. In such event, the Commission may suspend or modify any portion of this Proposal or take or refuse to take any other action permitted by law under the circumstances as they then exist, the terms and provisions of this Proposal notwithstanding.

40. The Parties acknowledge that the Commission, pursuant to its statutory responsibility, on its own motion or on request of any party, reserves the authority to act on the level of the Company's rates if the Commission determines that unforeseen circumstances have rendered the Company's rates or return on investment unreasonable, inadequate or excessive for the provision of safe and adequate service.

Binding Effect of Proposal

***116** 41. This Proposal represents a negotiated agreement and, except as otherwise expressly stated herein, none of the Parties shall be deemed to have approved, agreed to, or consented to any principle, methodology, or interpretation of law underlying or supposed to underlie any provision hereof, and this Proposal shall not be cited or relied upon with respect to any matters other than those specifically addressed herein.

Prior Agreements

42. To the extent that the provisions of this Proposal conflict with the provisions of the September 1999 Proposal or the June 2000 Settlement, the provisions of this Proposal shall control.

Modification of Proposal

43. Approval by the Commission of this Proposal shall constitute approval of all of its terms consistent with the intent of the Parties, as stated in the Introduction hereof. If the Commission approves this Proposal in its entirety or modifies it in a manner acceptable to the Parties, this Proposal shall be implemented in accordance with its terms. Because this Proposal is an integrated whole, with each provision in consideration for, in support of, and dependent on the others, any attempt to modify its terms may frustrate its purpose. Thus, if the Commission does not approve this Proposal in its entirety, without modification, each of the Parties reserves the right to withdraw its acceptance by serving written notice on the Commission and the other Parties and to renegotiate and, if necessary, to litigate, without prejudice, any or all issues as to which such Party agreed in this Proposal; such Party shall not be bound by the provisions of this Proposal, as executed or as modified, and this Proposal shall not take effect.

Effect of Agreement

44. This Proposal, if approved by the Commission, calls for RG&E to take specific actions to further the goals of the Commission with respect to the restructuring of the natural gas industry in the State of New York. Specifically:

a. This Proposal incorporates a number of inter-related undertakings by the Company, including but not limited to the following: (i) decreasing distribution rates; (ii) imputing a level of upstream capacity cost savings to customers; (iii) operating under a capacity cost incentive mechanism and with a penalty if costs increase and rewards if costs decrease; (iv) maintaining customer service quality and operating with penalties if service performance falls below certain standards; (v) maintaining a program of cast iron and bare steel main replacements; (vi) replacing and disposing of all mercury regulators on its system in an environmentally safe manner; (vii) implementing a program to provide benefits for low-income customers; (viii) working with counties in its service territory to facilitate retail choice for certain DSS clients; and (ix) implementing a program to educate residential and small commercial customers regarding retail access programs.

b. The Parties to this Proposal understand that RG&E's basis for having made each of the above commitments includes but is not limited to the following: RG&E shall have a reasonable opportunity to recover all prudently incurred investment and expenses and to earn a reasonable return on investments, including the costs of implementing improved gas delivery management systems through balancing charges, costs of Mandates, Catastrophic Events and Competition Implementation Costs, and upstream capacity costs in the manner provided for in this Proposal, in the September 1999 Proposal, in the June 2000 Settlement, as approved by the Commission, and/or in the Company's Commission-approved tariffs.

c. The Parties to this Proposal understand that RG&E's support for this Proposal is based on the following concepts: (i) the foregoing commitments and assurances are inextricably related; (ii) the rates established pursuant to this Proposal are just and reasonable throughout the Rate Term; (iii) the reasonable ***117** opportunity for RG&E to recover the prudently incurred costs referred to in sub-paragraph b, supra beyond the Rate Term is justified; (iv) this Proposal furthers the Policy Statement and other Commission policies identified in its generic proceedings pertaining to natural gas industry issues, including but not limited to Cases 93-G-0932, 97-G-1380, 98-G-1785, and related proceedings; and (v) approval of this Proposal is in the public interest.

Captions

45. All titles, subject headings, section titles and similar items are provided for the purpose of reference and convenience only and are not intended to affect the meaning, the content, or the scope of this Proposal.

State Environmental Quality Review Act Compliance

46. The Supplemental Environmental Assessment Form attached hereto as Appendix J accurately describes the potential environmental impacts, if any, that could result from implementation of the terms of this Joint Proposal, and the Commission's determination of significance regarding this Joint Proposal should be the adoption of a negative declaration.

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***138** APPENDIX E

RETAIL ACCESS CAPACITY PROGRAM

Overview of Retail Access Capacity Program

1. RG&E shall be entitled to implement a Retail Access Capacity Program (the 'Capacity Program') whereby capacity from liquid trading points -- Dawn, Ontario and Southpoint (i.e., all receipt points on the Dominion system south of Dominion's Valley Production Compressor Station) -- to the RG&E city gates at Mendon and Caledonia, respectively, will be released to Distribution Customers serving Small-Volume Customers in the Company's service area. As used herein, references to 'release' of capacity are intended to include all transfers to Distribution Customers of rights and obligations pertaining to capacity held by RG&E unless the context requires otherwise. The term 'Small-Volume Customer' refers to service points eligible to be served under Service Classification ('SC') SC No. 5 of the Company's gas distribution tariff, PSC No. 12. 'Empire Capacity' to be released shall include transportation capacity on TransCanada PipeLines Limited ('TCPL') and Union Gas Limited ('Union '), transportation capacity on Empire, and storage capacity on Union, if available. 'Dominion Capacity' to be released shall include transportation and storage capacity on Dominion. The capacity available for release shall be sufficient to meet a design day load of 390 MDT for the small-volume market, as well as to meet the operational design requirements of the RG&E distribution system. The 'small-volume market,' as used herein, refers to the market comprised of customers eligible to take service from natural gas Distribution Customers under SC No. 5 of PSC No. 12.

2. The Company's capacity commitments, expected to be in effect throughout the RRP Term, are described in Schedule 1 to this Appendix E. Capacity shall be released, in accordance with the methodology outlined below, as Small-Volume Customer load migrates to Distribution Customers.

Methodology for Initial Release

3. Upon commencement of the Capacity Program, RG&E shall make an initial pro-rata release of transportation and storage capacity on both the Empire and Dominion systems to Distribution Customers then serving migrated load. Such release shall be based on winter season design day requirements of the retail load served by each Distribution Customer. A sample calculation pertaining to a hypothetical release of capacity is shown in Schedule 2 to this Appendix E. This allocation method provides for RG&E's operational distribution system requirements. Operational distribution system requirements considered in the design of RG&E's capacity portfolio include maintaining the appropriate ratio of storage supply to flowing supply and the appropriate ratio of Empire deliveries to Dominion deliveries to ensure system

integrity. (Currently, approximately 50 percent of design day load is served from storage.)

Methodology for Subsequent Release/Recall

4. RG&E shall administer release of assets so as to maintain a correspondence between winter season design day requirements of the retail load served by each Distribution Customer and capacity released to that Distribution Customer on a periodic basis. As net load served by a Distribution Customer changes, the Company shall periodically make corresponding adjustments to the quantity of capacity released to the Distribution Customer by employing the capacity release and/or recall provisions pertaining to the pipelines involved. If the Distribution Customer becomes unqualified to sell gas on RG&E's system or transport gas on pipelines upstream of RG&E's city gates, RG&E shall recall all capacity released to that Distribution Customer. If the Distribution Customer fails to serve its customers, or if required for system reliability purposes, RG&E shall have the right to recall all capacity released to that Distribution Customer.

Release of Empire System Capacity

5. Release of capacity on Empire shall be carried out pursuant to the terms and conditions *139 of Empire's Tariff on file with the Commission, as such Tariff may be amended from time to time, and the terms and conditions of any separate agreement between RG&E and Empire pertaining to this subject. In the event of any conflict between the terms and conditions of the Tariff and any separate agreement, the terms and conditions of the latter shall control. **Release of capacity** on TCPL and Union shall be carried out by RG&E consistent with the terms and conditions of the Company's agreements with TCPL and Union.

Release of Dominion Capacity

6. **Release of capacity** on Dominion shall be carried out in a manner consistent with FERC requirements pertaining to **capacity release**.

Rates

7. The rates to be paid by any Distribution **Customer** taking **released** RG&E **capacity**

shall be RG&E's maximum contract rates pursuant to the tariffs and/or agreements applicable to the **released capacity**.

8. Where storage **assets** are **released** to a Distribution **Customer** in conjunction with this Program after the commencement of the storage injection season, RG&E shall transfer to the Distribution **Customer** a quantity of gas equivalent to a pro-rata **share** of gas that the Company has acquired to provide service to the migrated **customers**. The Distribution **Customer** shall pay RG&E a weighted average commodity cost of gas in storage, together with a contribution to storage **capacity** costs computed for each month in the period, beginning with April and ending at the transfer month, as follows:

$$\text{RSCAP} \cdot \text{WACOS} \cdot (1 - (\text{NMT} \times \text{AMT}))$$

where:

RSCAP = **Released Storage Capacity** (in DT);

WACOS = Weighted Average Cost of Storage (in \$/DT);

NMT = Normal Monthly Throughput (in DT); and

AMT = Normal Annual Throughput (in DT) divided by 12.

In the event that a Distribution Customer's load declines, necessitating a return of storage capacity to RG&E, the Company shall compensate the Distribution Customer for gas in storage at the same rate as the Company would sell commodity gas to the Distribution Customer pursuant to this paragraph 8.

Term

9. Releases of capacity pursuant to the Capacity Program shall be for a minimum term of one year; provided, however, that where the remaining term of a capacity agreement held by RG&E is less than one year, the release shall not, unless otherwise agreed by the Company and the Distribution Customer, exceed such remaining term; and provided further that all releases of capacity pursuant to the Capacity Program shall be subject to RG&E's right to recall the released capacity in the

event that a Distribution Customer loses load, as described in paragraph 4, supra.

Pipeline and Regulatory Requirements

10. Distribution Customers to whom capacity is to be, or has been, released pursuant to the Capacity Program shall cooperate with RG&E and meet all applicable requirements of the respective pipelines and governmental entities having jurisdiction of the relevant assets.

SCHEDULE 1 TO APPENDIX E

The assets listed below are included in RG&E's transportation and storage capacity portfolio and, except to the extent that the corresponding contractual terms and/or termination notice dates indicate otherwise, will be so included, and the corresponding costs recovered as provided in RG&E's approved tariffs throughout the RRP Term. Schedule 1 reflects the relinquishment by RG&E of **capacity** contracts upstream of Southpoint, which is acknowledged to be consistent with Commission ***140** policies, including in particular the Policy Statement. This statement is not to be construed as implying that relinquishment of **capacity** upstream of Dawn is inconsistent with Commission policies. To the extent that RG&E permanently **releases** such **capacity** or exercises a right of termination that takes effect during such period, or acquires new **capacity** contracts, the Company shall promptly notify the Commission of such circumstance and prepare and file an appropriate amendment to this Schedule 1 to Appendix E.

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***143** SCHEDULE 2 TO APPENDIX E

SAMPLE **CAPACITY RELEASE** CALCULATION

. Assume migrating **customer**(s) design day load of 10,000 dt

. Allocation between Empire and DTI systems:

Empire: $(172,500/390,000) * 10,000 = 4,423$ dt
DTI: $(218,000/390,000) * 10,000 = 5,590$ dt

. **Release of assets** on Empire system

Empire Pipeline: 4,423 dt
TransCanada Pipeline: $(138,000/172,500)*4,423 = 3,538$ dt
Union Storage:
Demand (withdrawal) $(93,280/172,500)*4,423 = 2,392$ dt
Capacity 2,392 dt * 35-day service = 83,720 dt

Note: Although utilized in this example, Union Storage is subject to regulatory approval, **asset** availability, economic evaluation and **management** approval.

Note: To accommodate for the difference in **released assets** between Empire and TransCanada, the marketer must either contract for firm TransCanada **capacity** back to Dawn, or demonstrate a firm supply contract at Chippawa or a point **downstream** of Chippawa.

. **Release of assets** on DTI system

Dominion Pipeline:
FT (seasonal) $(18,000/218,000)*5,590 = 462$ dt
FTNN-GSS $(112,000/218,000)*5,590 = 2,872$ dt
FTNN $(88,000/218,000)*5,590 = 2,256$ dt
Dominion Storage:
Demand (withdrawal) 2,872 dt
Capacity 2,872 dt * 40-day service = 114,880 dt

***144** APPENDIX F

CAPACITY INCENTIVE PROGRAM

Overview of **Capacity** Incentive Program

1. The **Capacity** Incentive Program ('CIP') consists of two elements, both of which are intended to encourage aggressive **management** of **capacity** costs: (a) a **Capacity** Cost Incentive; and (b) a **Capacity** Cost Imputation.

Capacily Cost Incentive

2. The **Capacity** Cost Incentive program is designed to **share**, between RG&E and its **customers**, the savings resulting from the difference between a base level of **capacity** costs and the actual **capacity** costs achieved. For purposes of this mechanism, the base level assumes that RG&E holds and uses existing transportation and storage **assets**. These **assets** are listed in Schedule 1 of Appendix E. Specifically, the existing **assets** to be included in the base level costs include ANR transportation and storage, and Great Lakes, Texas Gas and Transco transportation. (Transco costs shall be reflected on a net basis after **capacity release**.) Because Union storage is not an existing **asset**, it will be excluded from base level costs. Existing **assets** on Dominion, Empire and TCPL are not part of the **Capacity** Cost Incentive. The actual costs achieved will reflect the **assets** actually held during the period to which the computation pertains. Both the base and the actual levels will be updated monthly to account for changes in actual experience, as outlined in Schedule 1 hereto, entitled 'Elements of **Capacity** Incentive Program.'

3. RG&E shall retain 15 **percent** of the savings achieved that are greater than \$0.5 million and less than or equal to \$2.0 million. In the event that savings in excess of \$2.0 million are achieved, the Company shall also retain 50 **percent** of the amount that is greater than \$2.0 million and less than or equal to \$4.0 million, RG&E shall also retain 15 **percent** of the amount that exceeds \$4.0 million.

4. The Company shall bear the burden of 50 **percent** of increased costs, if any, that are greater than \$0.5 million and less than or equal to \$2.5 million. In the event that any increased costs exceed \$2.5 million, the Company shall bear 15 **percent** of the portion of such costs in excess of \$2.5 million.

5. RG&E's **share** of savings and the **customers'** **share** of increased costs, as outlined above, shall be collected or passed back, as the case may be, through the GCA beginning in July following the annual calculation of the **Capacity** Cost Incentive. Amounts to which either the Company or **customers** are entitled shall be added to or subtracted from GCA revenues actually received for the purpose of performing the annual GCA reconciliation for the 12 months ending August 2002, 2003 and 2004.

Capacity Cost Imputation

6. The **Capacity** Cost Imputation is intended to provide **customers** with a guaranteed level of short-term savings through the GCA. For purposes of this provision, 'short-term' refers to periods of one year or less. 'Savings' refers to **capacity release** savings, as well as net revenues from off-system **sales**, if any. Such savings shall be tracked over each consecutive one year period commencing in April. To the

extent that net savings exceed the imputed level, they shall be **shared** by **customers** and the Company on a 95 **percent**/5 **percent** basis, respectively, after subtraction of contractually determined payments made to the Company's portfolio **manager**, if any, for **capacity release** transactions included in the computation.

7. The imputed level of savings for the **Capacity** Cost Imputation shall be \$1,100,000 per year for the period beginning April 1, 2001 and extending through June 30, 2002. That level shall be \$500,000 per year for the period beginning July 1, 2002 and extending through March 31, 2004.

8. The calculation of short-term savings applicable to the Capacity Cost Imputation and the calculation of the Capacity Cost Incentive shall be made independently, and the results of each calculation shall be considered separately. For example, short-term savings related to a particular transaction will count towards the ***145** Capacity Cost Imputation. Savings resulting from the same transaction will be included in the calculation of actual capacity costs achieved for the purposes of the Capacity Cost Incentive. The impacts of each calculation shall be as described above in this Appendix F.

Term

9. The Capacity Incentive Program shall be in effect for the period April 1, 2001 through March 31, 2004.

Reporting Requirements

10. RG&E shall provide quarterly reports to Staff during each July, October, January and April during which the CIP is in effect; each such report shall pertain to the most recently ended quarter, beginning with the second calendar quarter of 2001. Such reports shall document year-to-date experience under the CIP. A final report shall be provided in April 2004.

***148** APPENDIX G LOW-INCOME PROGRAM

The Low-Income Program('LIP'),will be comprised of two segments. The first segment is the Residential Energy Consumer Assistance Program ('RECAP'). It will provide participants with arrears forgiveness, a reduction in monthly payments, and household budgeting and energy efficiency education. The second segment is the

Weatherization Grant Program. It will provide participants with energy efficiency and weatherization measures and energy efficiency education. Funding for this segment of the Program will begin July 1, 2001. These two segments of the LIP are described on the following pages. In addition, the schedule of customers and costs for the LIP is included in this Appendix.

Residential Energy Consumer Assistance Program ('RECAP') Program Objective

RECAP is designed to meet the following primary goals:

1. Provide customers with household budget counseling.
2. Provide customers with a more affordable payment plan for utility bills.

Program Design

Specifically, RECAP will provide the following components to participants:

1. Education -- General Budget Counseling

A budget session will be conducted by the Consumer Credit Counseling Service of Rochester. This session will cover methods to reduce current expenses and assist in understanding and developing approaches for household budgeting. Participants will be offered the option of individual budget counseling.

2. Affordable Payment Plan

RG&E will provide to program participants the following benefits:

a. Reduction in Monthly Payment

RG&E will reduce the participant's budget bill by \$20 each month, for a maximum of \$240 over the one-year period. For customers who default or exit the program early,

forgiveness of their annual \$240 budget reduction will be prorated, based on the number of monthly payments the customer made while active in the program.

b. Arrears Forgiveness

The program will provide total arrears forgiveness of \$250 per participant per year. For customers who default or exit the program early, arrears forgiveness will be prorated, based on the number of monthly payments the customer made while active in the program.

3. Energy Efficiency Measures

RG&E will refer customers to Action for a Better Community or Rural Opportunities for participation in their weatherization programs. Customers will be required to meet weatherization agency guidelines for weatherization program participation. Homeowners, in particular, will be encouraged to apply for these programs.

Eligibility Requirements

To be eligible for this program, customers will have to meet the following criteria:

1. The customer must be an RG&E gas or electric heating customer.
2. The customer must have outstanding arrears with RG&E and a service termination notice prior to application for enrollment in the program.
3. The customer must meet the income ***149** eligibility guidelines established for the Home Energy Assistance Program ('HEAP'), and must apply for the maximum number of HEAP grants available.
4. The customer must complete the Educational Component of the program.

5. The customer is expected to keep his or her account current, making all payments in full and on time.

6. The customer must agree to budget billing.

Program Components

1. Each participant will be in the program for one year. Upon completion of that period, RG&E will send a letter to the participant, advising him or her of other avenues available to assist with payment of the participant's energy bill. If the participant is completing his or her first year in the program, the participant will be advised of the option to continue in the program for a second year. Whether or not the participant chooses to apply for other available funds, the participant will be eligible for enrollment in the program for a second year.

2. RG&E will target a total participation of 900, enrolling that number as quickly as possible and will maintain that level of participants. These participants will be chosen from RG&E low-income customers with arrears and also, customers with arrears who are exiting the Department of Social Services ('DSS') Voucher Program. RG&E will target this program to limit electric heating customers to approximately 10 percent of total participation.

3. Each participant will be placed on budget billing; with a \$20 monthly reduction in that amount. The budget billing amount may be adjusted, as necessary, during the Program term. The participant will pay that reduced amount while enrolled in the program. Participants must remain current on their monthly bill throughout the term of the program. If the participant fails to keep his or her account current during the program, a reminder letter will be sent within approximately a 30-day period stating the account is not current and that payment is needed. If payment is not received within approximately a 60-day period, the participant will be dropped from the program. Normal collection activities will resume and the customer will be eligible for a Deferred Payment Agreement ('DPA').

4. Each participant who completes the program will receive \$490 of forgiveness consisting of \$250 of annual arrears forgiveness and \$240 annual forgiveness of the budget balance (\$20 per month reduction in their budget bill). For customers who default or exit the program early, arrears forgiveness and the budget reduction will be prorated, based on the number of payments the customer made while active in the program.

5. Each participant must apply for all available HEAP grants.
6. Prior to enrollment in the program, each participant would have completed a budget counseling session, conducted by the Consumer Credit Counseling Service of Rochester. This training is essential in assisting the participant with the development of good spending habits.
7. RG&E will suspend all collection activity and late payment charges during the period that the participant remains in compliance with the program criteria.
8. If a participant successfully completes the program and still has arrears, he or she will be advised of the availability of other avenues available to assist with payment of energy bills and will be offered a DPA.

Weatherization Grant Program (Effective July 1, 2001)

Program Objective

The Weatherization Grant Program is designed to provide energy efficiency and weatherization measures to assist customers in reducing their energy consumption. Action for a Better Community ('ABC') and Rural Opportunities ('RO ') are the two local weatherization agencies that work with their clients by installing weatherization measures appropriate for their homes and also providing energy efficiency education. RG&E will cooperate with ABC and RO, and designate grant monies that will enable the agencies to provide additional ***150** weatherization measures in homes where such services are needed most. The Weatherization Grant Program will be targeted to RG&E electric and gas heating customers.

Program Design

The program will be comprised of the following elements:

1. Education

The weatherization agency (ABC or RO) will provide an energy efficiency counseling session which will provide the customer with an understanding of how to reduce his or her energy usage.

2. Energy Efficiency Measures

After a home energy audit is completed by the weatherization agency (ABC or RO), the agency will determine the best manner in which to utilize grant monies in the participant's home.

Eligibility Requirements

To be eligible for this program, customers will have to meet the following criteria:

1. The customer must be an RG&E gas or electric heating customer.
2. The customer must meet the income eligibility guidelines established for the Home Energy Assistance Program ('HEAP') and must apply for the maximum number of HEAP grants available.

Program Components

1. Referrals for this program will come from RG&E's RECAP and from local weatherization agencies (ABC and RO) and shall be limited to RG&E gas or electric heating customers. All homeowners from RECAP will be referred to the weatherization grant programs. Grant monies are anticipated to provide weatherization measures to approximately 300 customers. The Program will be targeted to limit electric heating customers to approximately 10 percent of total participation.
2. The weatherization agencies will apply their expertise and experience to determine the most cost-effective efficiency measures for each participating customer. The agencies will provide RG&E with a proposed weatherization plan for each participant prior to installing any measures. RG&E will review these proposals to ensure consistency with program goals.

3. RG&E will receive reports from the weatherization agencies with information regarding the customers served and measures provided. The Company will periodically spotcheck installations to verify the accuracy of reporting. RG&E will obtain from the weatherization agencies written assurance that the funds provided will be targeted to RG&E heating customers in accordance with this program.

Reporting and Evaluation For Low-Income Program

RG&E will provide monthly and quarterly reports to the Office of Consumer Education and Advocacy, providing information regarding both segments of the LIP. Quarterly reports will be provided each October, January, April and July. Annual reports will be provided in July.

Quarterly Reports

Quarterly reports will provide the following information, on a monthly and rate-year to date basis:

RECAP

1. The number of enrollments in the program.
2. The number of active participants.
3. The number of participants receiving public assistance and not receiving public assistance.
4. The number of participants that have dropped out of the program.
5. The amount of arrears forgiveness provided.
- *151** 6. The amount of budget reduction provided.

Weatherization Grant Program

1. Names and account numbers for each customer referred to the program.
2. The weatherization measures delivered for each customer
3. The cost of weatherization services provided.
4. The date that weatherization services were installed or provided.
5. The number of gas heating and electric heating customers.

Annual Reports

Annual reports will provide the following additional information:

RECAP

1. A summary of program costs.
2. The number of gas versus electric heating participants.
3. The number of customers that attended a group budget counseling session.
4. The program drop-out rate.
5. A statistical summary of the reasons for leaving the program.
6. The average percentage bill coverage (i.e., total payments divided by total amount billed) per participant for the twelve months prior to entering the program.

7. The average percentage bill coverage per participant for the twelve months following participation in the program.
8. An evaluation of the impact of the program on collection costs, arrears and uncollectibles.
9. The average level of arrears for customers entering the program.

Weatherization Grant Program

1. An evaluation of the projected savings resulting from the energy efficiency and weatherization measures installed as a result of the program. This evaluation will be based upon standard projections of savings for the measures provided.

TABULAR OR GRAPHIC MATERIAL SET FORTH AT THIS POINT IS NOT DISPLAYABLE
TABULAR OR GRAPHIC MATERIAL SET FORTH AT THIS POINT IS NOT DISPLAYABLE

***153** APPENDIX H SERVICE QUALITY PERFORMANCE PROGRAM

The objective of the Service Quality Performance Program (SQPP) is to provide a means of ensuring that acceptable levels of customer service are maintained by the company in key areas of customer service as the industry is restructured. If the delivery of customer service deteriorates to any significant degree the company is subject to a financial penalty. The SQPP will consist of six measures as defined and listed below. The maximum allowable penalty will be 42 basis points of gas return on equity. Any penalties incurred under this program will be deferred for future disposition at the discretion of the Commission. All measures will apply to gas and electric business operations. SQPP periods are defined in paragraph 30 of this Joint Proposal.

Measure: Adjusted Bills

Definition: If more than one bill is rendered for the same billing cycle in order to correct a previously rendered bill for service, the second or subsequent bill(s) is the adjusted bill(s). The overall measure of adjusted bills is the percentage of adjusted bills compared to the total number of bills issued during the reporting

month. Bills that are adjusted prior to the initial bill being mailed to the customers and those rebilled due to customer reads are not included. Individual service point bills on a distribution customer's bills are also not included. For purposes of counting bills rendered, a bill containing gas and electric charges is counted as one bill.

The company will report the percentage of adjusted bills each month. The company will provide the monthly data on a quarterly basis. Performance will be evaluated over each SQPP period based on average monthly data over the period.

Targets:

Basis Points	Performance Levels
0	$\leq 2.25\%$
3.5	$> 2.25\%$ and $\leq 2.40\%$
7	$> 2.40\%$

Measure: PSC Complaint Rate

Definition: A PSC Complaint is a dispute filed by a, or on the behalf of a, consumer with the staff of the Office of Consumer Services. A dispute is classified as a complaint only if the consumer has already attempted to resolve it with the utility. A complaint rate per 100,000 customers is calculated by (a) dividing the total number of ***154** PSC complaints received in the reporting month by the number of customers at year-end as reported in the annual PSC report and (b) multiplying the result by 100,000.

The company complaint rate will be that shown on PSC report 'Complaint Rates of Major New York Utilities,' as adjusted for complaints changed to inquiries. Performance will be evaluated over each SQPP period based on the average of the 12-month rolling averages for each month over the period.

Targets:

Basis Points	Performance Levels
0	≤ 7
3.5	> 7 and ≤ 9
7	> 9

Measure: Estimated Meter Reads

Definition: The proportion of estimated meter reads is the total number of estimated meter reads expressed as a percentage of the total number of meters scheduled to be read for the purposes of rendering a bill. An estimated read is rendered because RG&E did not obtain an actual meter read at the time of the regularly scheduled meter read cycle. Estimated reads for a portion(s) of RG&E's service territory declared under a state of emergency are not included in the calculation. A customer read does not count as an estimated read. The percentage of estimated meter reads is calculated monthly. Monthly calculations are reported quarterly to the DPS staff. Performance will be evaluated for each SQPP period based upon average of monthly data over the period.

Targets:

Basis Points Performance Levels

0	<= 10%<= 12%
3.5	> 10% and
7	> 12%

Measure: Calls Answered Within 30 Seconds

Definition: The proportion of all telephone calls placed to RG&E's Customer Call Center that are responded to by an RG&E representative within 30 seconds. The overall measure is the percentage of customer telephone contacts answered by a representative within 30 seconds, compared to the total number of customer telephone contacts during normal Customer Call Center hours of 8:00 a.m. to 8:30 p.m. Monday through Friday and 9:00 a.m. to 1:00 p.m. Saturday. Calls received during a major storm, as currently defined in Part 97 of 16 NYCRR, will be excluded. The percentage of calls answered is calculated monthly. Monthly calculations are reported on a quarterly basis to DPS staff. Performance will be evaluated over each SQPP period based on average monthly data over the period.

Target:

Basis Points Performance Levels

0	>= 77%
3.5	>= 75% and < 77%
7	< 75%

Measure: Appointments Kept

Definition: A meeting with a customer by an RG&E representative in which the representative reaches the designated place at the scheduled time (e.g. day, half day or hour). Turn on's and turn off's are not included. The overall percentage of appointments kept is calculated using the number of appointments kept compared to the total number of appointments scheduled. The percentage of appointments kept is calculated on a monthly basis. Monthly calculations are reported quarterly to the DPS staff. Performance will be evaluated over each SQPP period based on average monthly data over the period.

Target:

Basis Points	Performance Levels
0	>= 97%
3.5	>= 95% and < 97%
7	< 95%

***155** Measure: Customer Transaction Survey

Definition: This score is an overall satisfaction rating of transactions customers have had with RG&E regarding billing, no lights, turn ons and shut offs, and tree trimming. The transactional overall satisfaction measure will be a composite score combining the satisfaction scores of residential and small commercial customers. The overall satisfaction score will be a weighted average based on each transaction type surveyed. The formula for calculating the overall satisfaction score is:

No. of surveys conducted for particular transaction type	
—	X Avg. Satisfaction Score for that Trans.
Total No. of Surveys	

The sum of the weighted average scores for each of the transaction types will give the overall score. This measure will be calculated on a quarterly basis and reported to PSC staff. Performance will be evaluated over each SQPP period based on average data over the period.

Targets:

Basis Points	Performance Levels
0	(≥ 7.6
3.5	≥ 7.2 and < 7.6
7	< 7.2

Reporting Requirements

The Company will provide a quarterly report to the PSC Staff of the performance incentive results. The report will include monthly information for each month in the quarter where available. Reports are due on the 20th day of January, April, July and October for the preceding quarter. The July report will include a compilation of the performance for each of the indicators for the applicable SQPP period and a determination of the maximum basis point penalty incurred.

Auditing

The Company will maintain, and make available upon reasonable notification, documentation supporting the measurement of all performance indicators. For those measures where data is automated, documentation may consist of summary information and may not necessarily involve detailed individual physical records.

APPENDIX I

CUSTOMER COMPETITION EDUCATION PLAN

I. Goals

The overall purpose of the Customer Competition Education Plan component of the RG&E RRP gas restructuring plan is to increase awareness and understanding of residential customers and small commercial customers of competitive choice. The goals of the plan are:

. Ensure that customers have '...sufficient and accurate information ...to use in making informed decisions' regarding their choice of gas suppliers (Gas Policy Statement);

- . Ensure that RG&E serves as an unbiased source of information in the community; and

- . Promote awareness, understanding, and acceptance of retail access plans.

II. Objectives

A. In order to meet these goals, RG&E will develop and carry out an outreach and education campaign integrating input from a variety of sources, such as customer focus groups, community meetings, community contacts and other venues.

***156** B. The program will promote concepts and messages that are intended to promote awareness and understanding of retail choice, including but not limited to the following options:

- . choice of natural gas supplier is available;

- . RG&E endorses competition;

- . safety, reliability, and customer service quality are not affected if one switches;

- . RG&E will continue to provide emergency services to all customers regardless of commodity supplier;

- . RG&E will not discriminate against customers who buy their commodity from another supplier, and

- . how to make competitive choices and switch gas suppliers.

C. RG&E will attempt to coordinate its customer education program with participating marketers in order to ensure that all efforts are effective and consistent.

D. RG&E will periodically evaluate program results and adjust program plans and messages if necessary to maintain progress towards the goals and objectives of the program.

III. Competitive Choice Survey

In order to evaluate the Company's performance in delivering the outreach and education program in their service territory, RG&E will conduct an annual survey incorporating questions into its existing customer satisfaction survey. The questions will be designed to measure residential customer awareness and understanding of gas competitive opportunities in RG&E's service territory. The survey is designed to be an accurate reflection of RG&E residential customer opinion with an estimated sampling error of 3 percentage points at a 95 percent confidence level. A baseline survey was conducted in November 1999. Following are the 1999 baselines for the understanding and awareness survey responses and their subsequent targets for November 2000-2001:

Awareness

- . November 1999 -- 66%
- . November 2000 -- 76% to 80%
- . November 2001-81% to 85%

Understanding

- . November 1999 -- 35%
- . November 2000 -- 45%
- . November 2001 -- 55%

A report of all survey results, specifically related to measuring residential customer awareness and understanding of gas retail choice, including raw results and computations, will be made available to signatory parties no later than January 30th following the end of the November surveys. Any disagreements about Rochester Gas and Electric's calculations that cannot be resolved by the signatory parties shall be referred to the Commission for resolution.

IV. Utility/Marketer customer education forum

At least once per year, the Company will hold a utility/marketer customer education forum, in which marketers and the Company will share plans for customer education and marketing activities for the coming year. The goal will be to provide an opportunity for RG&E and marketers operating in its territory to share information and coordinate plans to the extent that is deemed appropriate by all parties.

V. Annual Reports

The Company will report annually by June 30th to signatory parties:

- . the results of customer awareness and understanding surveys as described above;
- . the Company's customer education activities and expenditures, including messages, samples of materials under production, and use of audiences' and customers' input in program content, method and design; and
- . media reports.

VI. Budget

RG&E's incremental annual budget for ***157** this gas competition education plan is \$200,000. To the extent feasible, the Company will seek to inform and educate its customers about gas and electric retail choice concurrently in order to achieve maximum cost effectiveness and planning efficiency.

APPENDIX J

SUPPLEMENTAL ENVIRONMENTAL ASSESSMENT FORM

Prepared By: STAFF of the DEPARTMENT OF PUBLIC SERVICE, ROCHESTER GAS AND ELECTRIC CORPORATION, and the other PARTIES to the JOINT PROPOSAL PERTAINING TO RG&E'S NATURAL GAS RATES AND RESTRUCTURING PROGRAM

I. Introduction

This document provides the substantive information required by Appendix A of 6 NYCRR 617.20 of the regulations promulgated by the New York State Department of Environmental Conservation pursuant to the State Environmental Quality Review Act ('SEQRA'), Article 8 of the New York Environmental Conservation Law. An environmental assessment is an evaluation of the known or potential environmental consequences of a proposed action. Such an assessment also determines whether additional relevant information about such impacts is needed. Environmental assessments help involved and interested agencies identify their concerns about the action and provide guidance to the lead agency in making its determination of significance.

An Environmental Assessment Form ('EAF') provides an organized approach to identifying the information needed by the lead agency to make its determination of significance. A properly completed EAF describes a proposed action, its location, its purpose and its potential impacts on the environment. The EAF is the first step in the environmental impact review process and leads to either a positive declaration (requiring further analysis of the environmental impacts) or a negative declaration (requiring no further action) of potentially significant adverse environmental impact(s).

II. Environmental Assessment Form Information (Part I of EAF)

A. Sponsors:

Staff of the Department of Public Service and

Rochester Gas and Electric Corporation ('RG&E' or 'Company')

89 East Avenue

Rochester, New York 14649

B. Name of Action:

Public Service Commission ('PSC') Approval of the terms of the Joint Proposal
Pertaining To Natural Gas Rates And Restructuring

C. Location of Action:

RG&E Gas Service Territory

D. Description of Action:

The Company and other Parties are seeking under the Public Service Law of the State of New York approval of the terms of the Joint Proposal Pertaining To RG&E's Natural Gas Rates And Restructuring Program ('Joint Proposal'). On November 3, 1998, the PSC issued its Policy Statement Concerning the Future of the Natural Gas Industry in New York State and Order Terminating Capacity Assignment in Cases 93-G-0932 and 97-G-1380 ('Gas Policy Statement'). In the Gas Policy Statement, the Commission articulated its vision of the future of the natural gas industry, which is to 'facilitate development of a competitive market; eliminate barriers to competition; provide guidance to LDCs and marketers, especially with regard to expiring capacity contracts; and address customer inertia.' Gas Policy Statement at 3-4.

The PSC also set forth the following goals toward reaching its vision (id. at 4):

- 1) effective competition in the gas supply ***158** market for retail customers;
- 2) downward pressure on customer gas prices;
- 3) increased customer choice of gas supplies and service options;
- 4) ensuring a provider of last resort;

5) continuation of reliable service and maintenance of operations procedures that treat all participants fairly;

6) sufficient and accurate information for customers to use in making informed decisions;

7) availability of information that permits adequate oversight of the market to ensure its fair operation; and

8) coordination of federal and state policies affecting gas supply and distribution in New York State.

The PSC established three basic elements of the process to fulfill the goals and reach the vision established in the Gas Policy Statement. The first of those elements consists of discussions with each LDC on an individualized plan that would effectuate the PSC's vision. In preparation for those discussions, the PSC ordered LDCs to distribute to interested parties a proposal addressing the following issues:

1. A strategy to hold new capacity contracts to a minimum;
2. quantification of potential stranded costs and a plan to mitigate and manage them;
3. long term rate plan;
4. plan to further unbundle rates;
5. plan to enhance consumer education programs and facilitate customer participation in the commodity market; and
6. The possibility of a more aggressive role for LDCs in facilitating the move to a competitive market.

In addition to the distribution and negotiation of the LDCs' individualized plans, the PSC ordered the LDCs to file tariff leaves by February 1, 1999 that would eliminate mandatory capacity assignment and ordered Staff to begin collaborative proceedings addressing system operation and reliability issues, as well as the elimination of mandatory capacity assignment. The PSC also required Staff to establish a proceeding to address market power issues.

The PSC further stated that 'we have conducted an analysis under the State Environmental Quality Review Act ...and have determined that there will be no significant environmental impact from adoption of this Policy Statement and, therefore, we have issued a Notice of Determination of Non-Significance. ' Notice of Determination of Non-Significance at 9. Notwithstanding this conclusion, the Commission required that each LDC submit a draft environmental assessment form with its individual proposal.

On January 28, 2000, the Company submitted its individualized plan as contemplated by the Gas Policy Statement. Thereafter, the Signatory Parties entered into a Joint Proposal Pertaining to Natural Gas Rates and Restructuring ('Joint Proposal') modifying RG&E's plan (the Joint Proposal also incorporates certain rate changes due to recent tax legislation not further discussed herein, such legislation being exempt from SEQRA). Some of the key elements of the Joint Proposal include:

1. Gas revenue requirements, for the purpose of setting base rates for the period beginning July 1, 2000, decreased a total of \$2,806,000 from the levels in effect on June 30, 2000. Also, a volumetric surcharge will be initiated to recover the costs of a new low-income program.

2. **Sharing** of excess earnings over 12.5 **percent**, 90 **percent** for **customers**, 10 **percent** for the Company.

3. Revenue allocation and rate design for gas service completely separating the cost of gas (**capacity** and commodity), which will be identified as a separate component on the bills of residential **consumers** taking **sales** service from the company, from distribution or delivery rates; and increasing the **customer** charge to better reflect the actual cost of providing service.

4. Opportunity for implementation by the Company of a Retail Access **Capacity**

Program to facilitate migration to retail access whereby **capacity** from liquid trading *159 points to the Company's city gates will be **released** to Distribution **Customers** serving Small-Volume **Customers** in the Company's service area.

5. Development of a county aggregation program; implementation of a low income program; a **customer** competition education plan regarding gas competition, including an outreach and education component, and other provisions to improve retail access to a competitive gas market.

6. Financial incentives to RG&E related to **customer** service quality, gas safety and reliability, mitigation of **capacity** costs, **capacity release**, portfolio **management**, **customer** migration, and **customer** awareness and understanding of gas competitive opportunities.

7. Removal, replacement and disposal of all mercury regulators on the Company's system in a safe manner.

8. Establishment of a target for expenditures on cast iron and bare steel main replacement projects of \$9.5 million and, if that target is not met, deferral of the revenue requirement effect, with interest, of the difference for future disposition at the discretion of the Commission.

The Joint Proposal, as described above, involves changes in rate design, practices and economic arrangements affecting natural gas. Nothing inherent in the Joint Proposal calls for physical construction activities that would directly affect the environment except for the Mercury Regulator Replacement Program (described below), which is in the nature of a maintenance program that is a Type II Action under SEQRA not subject to review.

Accordingly, approval of the terms of the Settlement is an 'unlisted' action as defined in 6 NYCRR Section 617. While the regulations call for the use of a short form EAF in such instances, since this 'action' does not involve physical construction, the Parties chose to utilize a narrative EAF as opposed to the form EAF. III. Evaluation of Environmental Impacts (Part 2 of EAF)

The specific environmental impacts that might result from approval of the Joint Proposal are highly uncertain and difficult to predict. Other than the exception noted above, no aspect of the Joint Proposal would cause direct environmental

effects, since the Joint Proposal does not involve physical activities that might have impacts on the environment. Instead, approval of the Joint Proposal may contribute to the creation of circumstances that subsequently induce activities, which in turn may cause environmental effects. Nevertheless, the range of these potential effects has already been captured in the environmental review of the Gas Policy Statement.

In preparing this environmental assessment, the Parties have set out an evaluation of a range of conceivable secondary consequences of the Joint Proposal. The Parties have done so in order to assist the PSC in its evaluation of this issue. The Parties have relied on qualitative judgments as to the potential changes resulting from the proposed actions and the magnitude and importance of the corresponding potential environmental impacts.

A. Impact to Air

The Parties were unable to identify any direct effects on air emissions resulting from the Joint Proposal. However, since the Joint Proposal could lead to an increased demand for natural gas consumption, the impacts on air quality impacts of increasing gas consumption need to be examined.

In the Notice of Determination of Non-Significance for the Gas Policy Statement, the Commission summarized its conclusion concerning the environmental consequences of implementation of its 'vision' described in the Policy Statement, including in particular the separation of the LDCs' distribution function from the competitive market function. 'This policy, if effectuated, should result in a decline in the cost of gas for smaller customers, which will in turn, somewhat increase demand.' Notice of Determination of Non-Significance at 1. 'Since most of the increased demand is likely *160 to result from customers switching to gas from dirtier fuels, the net air quality impact of the increased sales will be neutral and possibly positive.'Id.

It is well known that the combustion of natural gas results in emissions of carbon dioxide, carbon monoxide and nitrogen oxides, Even so, burning natural gas results in significantly fewer emissions of these contaminants than burning other fuels such as oil or coal. Furthermore, coal is a significant source of sulfur dioxide emissions, while the use of natural gas does not produce this compound. In fact, the burning of fuel oil also produces sulfur dioxide as well as carbon dioxide and nitrogen oxides in greater quantities than are produced by natural gas. Of the three major fuel choices (coal, oil and gas), gas is clearly the cleanest combustion fuel from an environmental perspective.

The implementation of the Joint Proposal could further the demand for natural gas which in turn should further reductions in the emissions of sulfur dioxide, nitrogen oxides, particulates, and carbon dioxide. Thus, since clear environmental benefits may result from an air emissions perspective, no further environmental review is necessary.

B. Impact to Water

The Parties were unable to identify any direct effects on water quality resulting from the Joint Proposal. As discussed in the Impact to Air section above, the Joint Proposal could result, in concert with other companies' plans, in an increased demand for natural gas. This increased demand in turn could result in the construction of new gas transmission and distribution facilities to serve the increased demand. With such new construction, there could be the need to conduct work in environmentally sensitive areas such as wetlands or streams. While this work could potentially impact the environment, it would be subject to all current federal and state environmental regulatory requirements as well as review pursuant to SEQRA or Article 7 of the Public Service Law prior to construction. As the PSC found, 'since the individual distribution projects are subject to SEQRA review at the time of PSC action, these speculative impacts need not be considered at this time.'Id.

C. Impact to Land

The Parties were unable to identify any direct effects on land use resulting from the Joint Proposal. However, as indicated above, new construction or expansion of transmission or distribution facilities could have potential environmental impacts. These impacts, however, would be mitigated by regulatory requirements and review pursuant to SEQRA or Article 7 of the Public Service Law at the time as denoted by the PSC in its Determination of Non Significance.

D. Impact on Plants and Animals

The Parties were unable to identify any direct effects on plants and animals resulting from the Joint Proposal. However, as indicated above, new construction or expansion of transmission or distribution facilities could have potential environmental impacts. These impacts, however, would be mitigated by regulatory requirements and review pursuant to SEQRA or Article 7 of the Public Service Law at

the time as denoted by the PSC in its Determination of Non-Significance.

E. Impact on Agricultural Land Resources

The Parties were unable to identify any direct effects on agricultural land resources resulting from the Joint Proposal. However, new construction or expansion of transmission or distribution facilities could have potential environmental impacts. These impacts, however, would be mitigated by regulatory requirements and review pursuant to SEQRA or Article 7 of the Public Service Law at the time as denoted by the PSC in its Determination of Non-Significance.

F. Impact on Aesthetic Resources

The Parties were unable to identify any direct effects on aesthetic resources resulting from the Joint Proposal. However, new construction or expansion of transmission or distribution facilities could have potential environmental impacts. These impacts, however, would be mitigated by regulatory requirements and review pursuant to SEQRA or Article 7 of the Public Service Law at the time as denoted by the PSC in its Determination of Non-Significance.

G. Impact on Historic and Archeological Resources

The Parties were unable to identify any direct effects on historic and archeological resources resulting from the Joint Proposal. However, new construction or expansion of transmission or distribution ***161** facilities could have potential environmental impacts. These impacts, however, would be mitigated by regulatory requirements and review pursuant to SEQRA or Article 7 of the Public Service Law at the time as denoted by the PSC in its Determination of Non-Significance.

H. Impact on Open Space and Recreation

The Parties were unable to identify any direct effects on open space and recreation resulting from the Joint Proposal. However, new construction or expansion of transmission or distribution facilities could have potential environmental impacts. These impacts, however, would be mitigated by regulatory requirements and review pursuant to SEQRA or Article 7 of the Public Service Law at the time as denoted by the PSC in its Determination of Non-Significance.

I. Impact on Transportation

The Parties were unable to identify any direct effects on transportation resulting from the Joint Proposal. However, new construction or expansion of transmission or distribution facilities could have potential environmental impacts. These impacts, however, would be mitigated by regulatory requirements and review pursuant to SEQRA or Article 7 of the Public Service Law at the time as denoted by the PSC in its Determination of Non-Significance.

J. Impact on Energy

The Commission clearly contemplated the possibility that increased competition, rate decreases, and changes in rate design could promote increased energy usage. The Joint Proposal includes some revenue allocation and rate design changes, as well as a \$2.8 million decrease in revenue requirement. The revenue requirement decrease will be offset partially by a surcharge intended to recover the costs of a new low-income program. The surcharge will ultimately recover approximately \$ 1.0 million per year.

Under the Joint Proposal, changes would be made to the operation of the Gas Cost Adjustment ('GCA') consistent with the Commission's Memorandum and Resolution Revising 16 NYCRR Section 270.55, issued on April 13, 1999 ('1999 Memorandum'). Pursuant to these regulations, the Company will roll out the base cost of gas, currently at \$0.358 per therm plus losses at 1.85 percent, from all the rate levels for Service Classification No. 1 -- General Services ('SC No. 1 '). This will separate the cost of gas (commodity and capacity) from distribution, or delivery rates. The cost of gas will be identified as a separate component on the bill and collected along with other GCA elements.

The Company would also adopt the following GCA changes provided for in the 1999 Memorandum: (i) inclusion of risk management costs in the GCA; (ii) calculation of the fixed-cost component of the average cost of gas on the basis of weather-normalized volumes; (iii) calculation of the commodity component of the average cost of gas on the basis of estimated volumes for the month in which the GCA will be effective; (iv) reconciliation of the GCA at interim periods during the GCA reconciliation year, in addition to the annual reconciliation; and (v) filing a revised GCA within five days of the effective date of an initial GCA filing when the replacement of estimated prices with actual prices results in a change in the

average cost of gas of more than five percent.

The 30,001-100,000 and 100,001-1,000,000 therm rate blocks would be eliminated from SC No. 1. The remaining therm ***162** block rates in SC No. 1, other than the 0-3 therm block rate, would be reduced on a uniform percentage basis to reflect the decrease in revenue requirements. With gas costs rolled out of rates, the monthly customer charge for SC No. 1 service would increase to \$12 for the 0-3 therm rate block. To reflect this change, corresponding adjustments would be made to the 4-100, 101-500 and 501-1000 therm rate blocks.

The 1001-30,000, 30,001-100,000 and 100,001-1,000,000 block rates in Service Classification No. 3 -- Large General Service ('SC No. 3') would be reduced on a uniform percentage basis to reflect the decrease in revenue requirements. The monthly charge for SC No. 3 service, which applies to the first 1,000 therms of use, would remain at \$240.00.

The changes made to the block structure of SC No. 1 would also be made to Service Classification No. 5 -- Small General Service ('SC No. 5'). The remaining therm block rates in SC No. 5, other than the 0-3 therm block rate, would be reduced on a uniform percentage basis to reflect the decrease in revenue requirements. The customer charge for SC No. 5 service would increase to \$12 for the 0-3 therm rate block, with corresponding adjustments made to the 4-100, 101-500 and 501-1000 therm rate blocks.

The Parties believe that these modest changes will not have a significant adverse effect on the environment. Therefore, no further SEQRA review is required at this time.

K. Noise and Odor Impact

The Parties were unable to identify any direct effects on noise or odor resulting from the Joint Proposal. However, new construction or expansion of transmission or distribution facilities could have potential environmental impacts. These impacts, however, would be mitigated by regulatory requirements and review pursuant to SEQRA or Article 7 of the Public Service Law at the time as denoted by the PSC in its Determination of Non-Significance.

L. Impact on Public Health

The Parties were unable to identify any direct effects on public health resulting from the Joint Proposal since under the Joint Proposal the Company would continue to be responsible to maintain its facilities for the transmission and distribution of natural gas and for the delivery of gas to end use customers. Furthermore, as part of the Joint Proposal, RG&E will implement a Mercury Regulator Replacement Program. This program can only help to eliminate an element that can produce harm to the environment. Finally, since incremental demand for natural gas will result in a net reduction in air emissions, obviously there will be a resulting public health benefit from the Joint Proposal.

M. Impact on Growth and Character of Community or Neighborhood

The effect of the Joint Proposal will be to help reduce delivery service rates, which in turn will improve the economic well-being of communities in which gas is provided. Gas price reductions will help improve local business growth and contribute to the retention and growth of employment. It may also serve as another means to attract economic growth to New York State.

In order to educate consumers regarding their choices of gas commodity supplies, as described in the Settlement, the Company will implement a Customer Competition Education Plan to educate consumers about deregulation so that they can make informed decisions when taking advantage of the competitive marketplace.

IV. Significance of Environmental Impacts

After a review of the changes called for under the Joint Proposal, the Parties conclude that no further environmental review is necessary with respect to the Joint Proposal. No significant environmental impact was identified that would result from the subject Joint Proposal.

January 25, 2001

***163** The party whose signature follows subscribes to the foregoing Joint Proposal.

Staff of the Department of Public Service

Rochester Gas and Electric Corporation
Dominion Transmission, Inc.
Energetix, Inc.
Amerada Hess Corporation

FOOTNOTES

Order

FN1 Case 99-G-1589, Order Approving Petition (issued September 30, 1999); Order Adopting Terms of Settlement Agreement (issued July 31, 2000).

FN2 A copy of the document entitled 'Joint Proposal Pertaining to Rochester Gas and Electric Corporation's Natural Gas Rates And Restructuring Program,' (Joint Proposal) is attached.

FN3 Cases 93-G-0932 and 97-G-1380, Policy Statement Concerning the Future of the Natural Gas Industry in New York State and Order Terminating Capacity Assignment (issued November 3, 1998), (Gas Policy Statement).

FN4 Other features of the Joint Proposal, principally those that are dependent on capacity assets, are subject to a more extended term. The March 31, 2004 expiration date for these items reflects the expiration of certain key transportation and storage contracts.

FN5 The first rate year is from July 1, 2000 to June 30, 2001. The second rate year is from July 1, 2001 to June 30, 2002.

FN6 16 NYCRR §166.17(b).

FN7 The SC No. 1 minimum charge of \$6.90 includes three therms of gas; without the gas, it is comparable to the SC No. 5 minimum charge of \$5.81, which excludes gas.

FN8 Gas Policy Statement at 8.

Joint Proposal

FN1 Proceeding on Motion of the Commission to Address Issues Associated with the Restructuring of the Emerging Competitive Natural Gas Market.

FN2 In the Matter of Issues Associated with the Future of the Natural Gas Industry and the Role of the Local Gas Distribution Companies.

FN3 E.g., Case 98-G-1785, In the Matter of the Allocation by Local Distribution Companies of Strandable Gas Capacity Costs Caused by Customer Migration.

FN4 See June 2000 Settlement, Par. 12.

FN5 See 16 NYCRR § 166.17(b).

FN6 See paragraph 11, *infra*.

FN7 E.g., Case 00-M-1556, In the Matter of the Proposed Accounting and Ratemaking for the Tax Law Changes Included in the 2000-2001 New York State Budget, Proposed Rule Making (NYS Register, November 1, 2000).

FN8 In the Matter of Competitive Opportunities Regarding Electric Service.

FN9 See June 2000 Settlement, App. A, p. 2, Section 2.3.

EDITOR'S APPENDIX

PUR Citations in Text

N.Y.] The Allocation by Local Distribution Companies of Strandable Gas Capacity, 192 PUR4th 109, Case No. 98-G-1785, Feb. 22, 1999.

N.Y.] Re Future of the Natural Gas Industry and the Role of Local Distribution Companies, 189 PUR4th 1, Case No. 97-G-1380, Nov. 3, 1998.

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208 P.U.R.4th 97, 2001 WL 490516 (N.Y.P.S.C.)

(Cite as: 208 P.U.R.4th 97)

N.Y.] Re Restructuring of the Emerging Competitive Natural Gas Market, 189 PUR4th 1, Case No. 93-G-0932, Nov. 3, 1998.

N.Y.] Re Rochester Gas & E. Co., 203 PUR4th 453, Case No. 98-G-1589, July 31, 2000.

END OF DOCUMENT

Westlaw.

215 P.U.R.4th 185

215 P.U.R.4th 185, 2002 WL 554356 (Conn.D.P.U.C.)

(Publication page references are not available for this document.)

Page 1

H

Re Yankee Gas Services Company
Docket No. 01-05-19PH01

Connecticut Department of Public Utility Control
January 30, 2002

ORDER requiring a natural gas local distribution company (LDC) to reduce its rates and charges by \$4.006 million (1.25%), reflecting an authorized rate of return on equity of 11%, and a rate of return on rate base of 8.91%. The authorized rate of return on equity reflects the results of a discounted cash flow analysis, as adjusted by eight basis points for risk associated with the LDC's lack of a weather normalization adjustment clause. The reduction in revenue requirement is applied on a volumetric throughput basis, pending the completion of a rate design proceeding.

Department approves an infrastructure expansion rate mechanism (IERM) to address significant capital expenditures that will be made by the LDC subsequent to the rate year. The IERM provides the LDC with the opportunity to increase rates as system expansion projects are completed and included in plant-in-service -- without the necessity of filing new rate cases. If the costs of a system expansion project are to be included in the IERM, the LDC must demonstrate that the project will produce a positive internal rate of return, that all construction costs have been prudently incurred, and that contributions in aid of construction have been maximized. Furthermore, for any project that has a total 30-year IRR less than 10%, the department will cap the allowed charges through the IERM so that ratepayers do not fund the difference between the project's IRR and a 10% IRR. Department declines to include a proposed liquified natural gas facility as an IERM project, finding that it would be premature to do so.

A mechanism for the **sharing** of earnings in excess of the authorized rate of return on equity (ROE) is approved for the **LDC**. The mechanism provides for annual variable **sharing** as follows:

- . for the year ending 2002, 75% shareholder and 25% **ratepayer sharing** of the first 100 basis points over the allowed ROE and 50/50 **sharing** for all additional earnings;
- . for the years ending 2003 and 2004, 75% shareholder and 25% **ratepayer sharing** of

the first 50 basis points over the allowed ROE and 50/50 **sharing** for all additional earnings; and

. for the year ending 2005, 50/50 **sharing** of all earnings in excess of the allowed ROE.

The **ratepayer share** of excess earnings would be used first to offset any rate increases that would otherwise result from the IERM. Any remaining **ratepayer share** of earnings would be allocated to **customer** classes consistent with the allocation of revenue requirements and allocated within **customer** classes on a volumetric basis.

Department approves, on a permanent basis, a line extension policy that permits the **LDC**, at shareholder risk, to install and pay for all or a portion of main extension costs to new interruptible **customers**. The capital costs are excluded from rate base until the **assets** are fully amortized over a ten year period. The policy provides for the **sharing** with **ratepayers** of any margin on service to the new interruptible **customers**, while shareholders agree to absorb any loss in the event that revenues do not recover the costs of the extension.

In determining revenue requirement, the department adjusts the **LDC's** test-year 2000 gas costs downward by \$60.85 million, based on its determination that year 2000 costs were anomalously high. The revenue requirement of the **LDC** is further reduced to account for synergy savings associated with the merger of the holding company parent of the **LDC**, Yankee Energy System, Inc., with Northeast Utilities.

Department declines to adjust rate base for a regulatory pension deferred liability credit associated with the merger. It explains that an adjustment to rate base is not appropriate inasmuch as the LDC received no cash from ratepayers and is not using the credit for corporate purposes.

Department continues its practice of allowing the LDC to recover prudently-incurred environmental remediation costs associated with the containment or removal of coal tar deposits at its former manufactured gas plant sites. Insurance proceeds are credited against remediation expenses, and costs incurred between rate cases are deferred until they can be reviewed for prudence in the succeeding case.

Department denies rate recovery of the cost of a gas marketing incentive program,

finding that state statute prohibits **ratepayer** funding of programs that encourage fuel switching.

Recognizing the importance of ensuring that affiliate transactions are conducted at arm's length and that transaction costs are properly allocated between regulated and unregulated operations, the department requires the **LDC** to file annual reports detailing its transactions with affiliates.

Department approves a service quality plan for the **LDC**, with performance measures and penalties designed to protect **customers** against deterioration of service.

Commissioner Arthur dissents arguing that the IERM violates the prohibition against single-issue rate making and that the earnings **sharing** mechanism provides the **LDC** with an exorbitant rate of return.

P.U.R. Headnote and Classification

1.

RATES

s120.1

Ct.D.P.U.C. 2002

[CONN.] Reasonableness -- Test period -- Historical test year -- Authorized adjustments -- Natural gas rate proceeding.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

2.

VALUATION

s25

Ct.D.P.U.C. 2002

[CONN.] Ascertaining rate base -- Value for rate making -- Date of valuation --
Midpoint of proposed rate year -- Natural gas rate proceeding.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

3.

VALUATION

s96

Ct.D.P.U.C. 2002

[CONN.] Accumulated depreciation -- Adjustment to reflect reduced depreciation
expense -- Natural gas local distribution company.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

4.

VALUATION

s192.1

Ct.D.P.U.C. 2002

[CONN.] Deferred income taxes -- Adjustment to reflect increased deferred federal income tax expenses -- Natural gas local distribution company.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

5.

VALUATION

s293

Ct.D.P.U.C. 2002

[CONN.] Working capital -- Lead-lag study -- Adjustment to correspond to allowed rate year amounts -- Natural gas local distribution company.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

6.

VALUATION

215 P.U.R.4th 185
215 P.U.R.4th 185, 2002 WL 554356 (Conn.D.P.U.C.)
(Publication page references are not available for this document.)

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s309

Ct.D.P.U.C. 2002

[CONN.] Cash working capital -- Particular allowances -- Natural gas local distribution company.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

7.

VALUATION

s281

Ct.D.P.U.C. 2002

[CONN.] Natural gas local distribution company -- Property included in rate base -- Plant additions -- Inclusion subject to review under Infrastructure Expansion Rate Mechanism.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

8.

VALUATION

s223

Ct.D.P.U.C. 2002

[CONN.] Property included -- Plant additions -- Inclusion subject to review under Infrastructure Expansion Rate Mechanism -- Natural gas local distribution company.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

9.

VALUATION

s181

Ct.D.P.U.C. 2002

[CONN.] Charges to capital -- Prepayments -- Regulatory assessment -- Insurance -- Inventory -- Property taxes -- Natural gas local distribution company.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

10.

VALUATION

s192

Ct.D.P.U.C. 2002

[CONN.] Regulatory pension liability -- Rate base treatment -- No adjustment required -- Natural gas local distribution company.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

11.

VALUATION

s192

Ct.D.P.U.C. 2002

[CONN.] Reserves -- Regulatory assets -- Financial Accounting Standards Statement No. 106 -- Unamortized balance of deferred post-retirement benefits obligation -- Rate base reduction -- Natural gas local distribution company.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

12.

VALUATION

s257.2

Ct.D.P.U.C. 2002

[CONN.] Unamortized balances -- Regulatory assets -- Financial Accounting Standards Board Statement No. 106 -- Deferred postretirement benefits obligation -- Rate base reduction -- Natural gas local distribution company.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

13.

VALUATION

s192

Ct.D.P.U.C. 2002

[CONN.] Reserves -- Regulatory assets -- Supplemental employee retirement plan -- Deferred credit -- Reduction to rate base -- Natural gas local distribution company.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

14.

VALUATION

s169

Ct.D.P.U.C. 2002

[CONN.] Charges to capital -- Reserves -- Accounts receivable -- Uncollectibles -- Natural gas local distribution company.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

15.

VALUATION

s192

Ct.D.P.U.C. 2002

[CONN.] Property sold -- Net rate base impact -- Natural gas local distribution company.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

16.

REVENUES

s15

Ct.D.P.U.C. 2002

[CONN.] Sale of utility plant -- Amortization of gain -- Natural gas local distribution company.

215 P.U.R.4th 185

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215 P.U.R.4th 185, 2002 WL 554356 (Conn.D.P.U.C.)

(Publication page references are not available for this document.)

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

17.

VALUATION

s192

Ct.D.P.U.C. 2002

[CONN.] Natural gas restructuring transition costs -- Transition credit account -- True-up -- Rate base reduction -- Natural gas local distribution company.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

18.

REVENUES

s2

Ct.D.P.U.C. 2002

[CONN.] Forecasts -- Test-year sales -- Weather normalization adjustment -- Natural gas local distribution company.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

19.

REVENUES

s4

Ct.D.P.U.C. 2002

[CONN.] Forecasts -- Test-year sales -- Customer growth adjustment -- Natural gas local distribution company.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

20.

REVENUES

s2

Ct.D.P.U.C. 2002

[CONN.] Forecasts -- Service contract work -- Appliance contracts -- Natural gas local distribution company.

Re Yankee Gas Services Company

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215 P.U.R.4th 185, 2002 WL 554356 (Conn.D.P.U.C.)

(Publication page references are not available for this document.)

P.U.R. Headnote and Classification

21.

REVENUES

s12

Ct.D.P.U.C. 2002

[CONN.] Natural gas local distribution company -- Billable appliance services -- Increase in hourly billing rates -- Rejection of flat-rate pricing.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

22.

MERCHANDISING AND JOBBING

s2

Ct.D.P.U.C. 2002

[CONN.] Jurisdiction -- State department -- Gas service work -- Appliance maintenance and repair -- Cost recovery -- Natural gas local distribution company.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

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(Publication page references are not available for this document.)

23.

RATES

s384

Ct.D.P.U.C. 2002

[CONN.] Natural gas -- Kinds of service -- Appliance maintenance and repair -- Pricing -- Rejection of flat-rate pricing -- Local distribution company.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

24.

REVENUES

s5

Ct.D.P.U.C. 2002

[CONN.] Interruptible service -- Target margin -- Sharing of revenues in excess of target -- Sharing percentages -- Natural gas local distribution company.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

25.

215 P.U.R.4th 185

215 P.U.R.4th 185, 2002 WL 554356 (Conn.D.P.U.C.)

(Publication page references are not available for this document.)

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EXPENSES

s51

Ct.D.P.U.C. 2002

[CONN.] Allocated expenses from affiliate -- Adjustment for historically disallowed costs -- Natural gas local distribution company.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

26.

EXPENSES

s83

Ct.D.P.U.C. 2002

[CONN.] Payments to affiliate -- Allocated expenses -- Adjustment for historically disallowed costs -- Natural gas local distribution company.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

27.

EXPENSES

215 P.U.R.4th 185
215 P.U.R.4th 185, 2002 WL 554356 (Conn.D.P.U.C.)
(Publication page references are not available for this document.)

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s48

Ct.D.P.U.C. 2002

[CONN.] American Gas Association dues -- Disallowance of governmental relations and lobbying costs -- Natural gas local distribution company.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

28.

EXPENSES

s81

Ct.D.P.U.C. 2002

[CONN.] Corporate headquarters -- Annual lease, operating, maintenance, and moving costs -- Natural gas local distribution company.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

29.

EXPENSES

s89

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(Publication page references are not available for this document.)

Ct.D.P.U.C. 2002

[CONN.] Annual regulatory assessment -- Use of current actual assessment --
Natural gas local distribution company.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

30.

EXPENSES

s19

Ct.D.P.U.C. 2002

[CONN.] Depreciation -- Determination of annual expense -- Natural gas local
distribution company.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

31.

DEPRECIATION

s31

Ct.D.P.U.C. 2002

215 P.U.R.4th 185
215 P.U.R.4th 185, 2002 WL 554356 (Conn.D.P.U.C.)
(Publication page references are not available for this document.)

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[CONN.] Calculation of annual depreciation -- Life of property and salvage --
Natural gas local distribution company.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

32.

DEPRECIATION

s55

Ct.D.P.U.C. 2002

[CONN.] Natural gas local distribution company -- Calculation of annual
depreciation -- Life of property and salvage.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

33.

EXPENSES

s49

Ct.D.P.U.C. 2002

[CONN.] Postretirement benefits other than pensions -- Voluntary employee benefits
association trust -- Accrual accounting -- Financial Accounting Standards Board

Statement No. 106 -- Natural gas local distribution company.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

34.

EXPENSES

s49

Ct.D.P.U.C. 2002

[CONN.] Postretirement benefits other than pensions -- Amortization of regulatory assets -- Financial Accounting Standards Board Statement No. 106 -- Natural gas local distribution company.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

35.

EXPENSES

s49

Ct.D.P.U.C. 2002

[CONN.] Pensions -- Qualified plans -- Natural gas local distribution company.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

36.

EXPENSES

s49

Ct.D.P.U.C. 2002

[CONN.] Retirement programs -- Supplemental employee retirement program -- Natural gas local distribution company.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

37.

EXPENSES

s49

Ct.D.P.U.C. 2002

[CONN.] Retirement programs -- 401(k) plan -- Adjustment of changes in payroll -- Natural gas local distribution company.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

38.

EXPENSES

s20

Ct.D.P.U.C. 2002

[CONN.] Environmental remediation -- Manufactured gas plant sites -- Containment or removal of coal tar deposits -- Amortization of deferred expenses -- Credit for insurance proceeds -- Natural gas local distribution company.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

39.

EXPENSES

s20

Ct.D.P.U.C. 2002

[CONN.] Environmental remediation -- Manufactured gas plant sites -- Containment or removal of coal tar deposits -- Carrying costs of deferred balances -- Natural gas local distribution company.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

40.

EXPENSES

s125

Ct.D.P.U.C. 2002

[CONN.] Natural gas local distribution company -- Environmental remediation --
Manufactured gas plant sites -- Containment or removal of coal tar deposits --
Amortization of deferred expenses -- Credit for insurance proceeds.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

41.

EXPENSES

s10

Ct.D.P.U.C. 2002

[CONN.] Ascertainment -- Inflation adjustment -- Natural gas local distribution
company.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

42.

EXPENSES

s26

Ct.D.P.U.C. 2002

[CONN.] Marketing and promotion -- Gas appliance incentive -- Grounds for denial -- Statutory bar on rate recovery of fuel switching incentives -- Natural gas local distribution company.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

43.

EXPENSES

s125

Ct.D.P.U.C. 2002

[CONN.] Natural gas local distribution company -- Calculation of revenue requirement -- Reduction for merger synergies.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

44.

EXPENSES

s26

Ct.D.P.U.C. 2002

[CONN.] Marketing -- System expansion -- Acquisition of new customers -- Grounds for disallowance -- Encouragement of fuel switching -- Statutory bar on rate recovery -- Natural gas local distribution company.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

45.

EXPENSES

s95

Ct.D.P.U.C. 2002

[CONN.] Payroll expense -- New employees -- Natural gas local distribution company.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

46.

EXPENSES

s62

Ct.D.P.U.C. 2002

[CONN.] Liability insurance -- Relation to reserve for injuries and damages --
Natural gas local distribution company.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

47.

EXPENSES

s62

Ct.D.P.U.C. 2002

[CONN.] Reserve of public liability injuries and damages -- Deferral of payments
in excess of reserve -- Natural gas local distribution company.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

48.

EXPENSES

s114

Ct.D.P.U.C. 2002

[CONN.] Income taxes -- Interest synchronization -- Natural gas local distribution company.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

49.

EXPENSES

s114

Ct.D.P.U.C. 2002

[CONN.] Deferred federal income taxes -- Reduction to operating expenses -- Natural gas local distribution company.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

50.

EXPENSES

s109

Ct.D.P.U.C. 2002

[CONN.] Gross earnings tax -- Blended rate -- Natural gas local distribution company.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

51.

EXPENSES

s109

Ct.D.P.U.C. 2002

[CONN.] Property taxes -- Method of calculation -- Rate treatment of refund of past taxes and interest -- Natural gas local distribution company.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

52.

EXPENSES

s118

Ct.D.P.U.C. 2002

[CONN.] Uncollectibles -- Hardship programs -- Amortization of deferred balances
-- Natural gas local distribution company.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

53.

EXPENSES

s118

Ct.D.P.U.C. 2002

[CONN.] Uncollectibles -- Accounts receivable expense -- Natural gas local
distribution company.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

54.

EXPENSES

s125

Ct.D.P.U.C. 2002

[CONN.] Natural gas local distribution company -- Required change in operating income -- Revenue conversion factor.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

55.

EXPENSES

s126

Ct.D.P.U.C. 2002

[CONN.] Natural gas local distribution company -- Base cost of gas -- Adjustment to test year -- Normalization adjustments -- Forecasted price and consumption data.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

56.

RETURN

s15

Ct.D.P.U.C. 2002

[CONN.] Reasonableness -- Cost of capital allowances -- Legal standard.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

57.

RETURN

s26.1

Ct.D.P.U.C. 2002

[CONN.] Reasonableness -- Capital structure -- Inclusion of short-term debt --
Natural gas local distribution company.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

58.

RETURN

s26.1

Ct.D.P.U.C. 2002

[CONN.] Reasonableness -- Capital structure -- Proposed exclusion of short-term
debt -- Recovery of short-term financing costs through allowance for funds used
during construction -- Discussion.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

59.

RETURN

s26.2

Ct.D.P.U.C. 2002

[CONN.] Reasonableness -- Cost of debt capital -- Short-term and long-term debt cost rates -- Natural gas local distribution company.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

60.

RETURN

s26.4

Ct.D.P.U.C. 2002

[CONN.] Reasonableness -- Cost of equity -- Non-publicly traded company -- Estimation methodology -- Use of proxy group -- Natural gas local distribution company.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

61.

RETURN

s26.4

Ct.D.P.U.C. 2002

[CONN.] Reasonableness -- Cost of equity -- Estimation methodologies -- Preference for discounted cash flow model -- Critique of risk premium approach and other non-DCF techniques.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

62.

RETURN

s26.4

Ct.D.P.U.C. 2002

[CONN.] Reasonableness -- Cost of equity -- Estimation methodology -- Discounted cash flow model -- Risk adjustment for lack of a weather normalization adjustment clause -- Natural gas local distribution company.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

63.

RETURN

s92

Ct.D.P.U.C. 2002

[CONN.] Natural gas local distribution company -- Overall rate of return -- Reasonableness.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

64.

PUBLIC UTILITIES

s78

Ct.D.P.U.C. 2002

[CONN.] Alternative regulatory framework -- Natural gas local distribution company -- Earnings sharing mechanism.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

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(Publication page references are not available for this document.)

65.

RETURN

s26.4

Ct.D.P.U.C. 2002

[CONN.] Reasonableness -- Sharing of excess earnings -- No deadband approach --
Natural gas local distribution company.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

66.

RETURN

s92

Ct.D.P.U.C. 2002

[CONN.] Natural gas local distribution company -- Sharing of excess earnings -- No
deadband approach.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

67.

REVENUES

s5

Ct.D.P.U.C. 2002

[CONN.] Natural gas local distribution company -- Earnings in excess of authorized return on equity -- Sharing mechanism -- No deadband approach.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

68.

RETURN

s26.4

Ct.D.P.U.C. 2002

[CONN.] Reasonableness -- Sharing of excess earnings -- Annual variable sharing mechanism -- Natural gas local distribution company.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

69.

RETURN

s92

Ct.D.P.U.C. 2002

[CONN.] Natural gas local distribution company -- Sharing of excess earnings -- Annual variable sharing mechanism -- Natural gas local distribution company.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

70.

REVENUES

s5

Ct.D.P.U.C. 2002

[CONN.] Natural gas local distribution company -- Earnings in excess of authorized return on equity -- Annual variable sharing mechanism -- Natural gas local distribution company.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

71.

RATES

s380

Ct.D.P.U.C. 2002

[CONN.] Natural gas rate design -- Special factors -- Earnings sharing mechanism
-- Allocation of ratepayer share of excess earnings.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

72.

PUBLIC UTILITIES

s78

Ct.D.P.U.C. 2002

[CONN.] Alternative regulatory framework -- Natural gas local distribution company
-- Post-merger service quality -- Performance measures and standards -- Penalty
mechanism.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

73.

SERVICE

s332

Ct.D.P.U.C. 2002

[CONN.] Natural gas local distribution company -- Post-merger service quality -- Performance measures and standards -- Penalty mechanism.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

74.

SERVICE

s124

Ct.D.P.U.C. 2002

[CONN.] Quality -- Performance standards and measures -- Penalty mechanism -- Natural gas local distribution company.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

75.

VALUATION

s281

Ct.D.P.U.C. 2002

[CONN.] Natural gas local distribution company -- System expansion projects -- Recognition between rate cases -- Infrastructure expansion rate mechanism.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

76.

SERVICE

s188

Ct.D.P.U.C. 2002

[CONN.] System expansion projects -- Burden of cost -- Infrastructure expansion rate mechanism -- Natural gas local distribution company.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

77.

SERVICE

s199

Ct.D.P.U.C. 2002

[CONN.] Natural gas system expansion projects -- Burden of cost -- Infrastructure expansion rate mechanism -- Local distribution company.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

78.

AUTOMATIC ADJUSTMENT CLAUSES

s46

Ct.D.P.U.C. 2002

[CONN.] Plant-based adjustments -- System expansion projects -- Recognition between rate cases -- Infrastructure expansion rate mechanism -- Natural gas local distribution company.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

79.

RATES

s380

Ct.D.P.U.C. 2002

[CONN.] Natural gas rate design -- Special factors -- System expansion projects -- Recognition between rate cases -- Infrastructure expansion rate mechanism -- Local distribution company.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

80.

EXPENSES

s125

Ct.D.P.U.C. 2002

[CONN.] Natural gas local distribution company -- System expansion projects --
Recognition between rate cases -- Infrastructure expansion rate mechanism.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

81.

SERVICE

s188

Ct.D.P.U.C. 2002

[CONN.] Line extension policy -- New interruptible customers -- Burden of cost --
Shareholder funding -- Contract pricing -- Margin sharing -- Natural gas local
distribution company.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

82.

SERVICE

s199

Ct.D.P.U.C. 2002

[CONN.] Natural gas -- Interruptible line extension policy -- Burden of cost -- Shareholder funding -- Contract pricing -- Margin sharing -- Local distribution company.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

83.

REVENUES

s5

Ct.D.P.U.C. 2002

[CONN.] Natural gas -- New interruptible customers -- Contract pricing -- Margin sharing -- Local distribution company.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

84.

RATES

s384

Ct.D.P.U.C. 2002

[CONN.] Natural gas rate design -- New interruptible customers -- Contract pricing
-- Local distribution company.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

85.

REVENUES

s5

Ct.D.P.U.C. 2002

[CONN.] Natural gas -- Capacity release credits -- Off-system sales -- Margin
sharing allocation -- Local distribution company.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

86.

GAS

s7

Ct.D.P.U.C. 2002

[CONN.] Procurement practices -- Hedging -- Allocation of losses or gains -- Local distribution company.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

87.

AUTOMATIC ADJUSTMENT CLAUSES

s32

Ct.D.P.U.C. 2002

[CONN.] Gas procurement practices -- Hedging -- Allocation of losses or gains -- Local distribution company.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

88.

VALUATION

s281

Ct.D.P.U.C. 2002

[CONN.] Natural gas local distribution company -- Proposed liquified natural gas plant -- Request for inclusion as infrastructure expansion rate mechanism project -- Grounds for denial.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

89.

EXPENSES

s125

Ct.D.P.U.C. 2002

[CONN.] Natural gas local distribution company -- Proposed liquified natural gas plant -- Request for inclusion as infrastructure expansion rate mechanism project -- Grounds for denial.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

90.

GAS

s5.1

Ct.D.P.U.C. 2002

[CONN.] Plant safety -- Liquified natural gas plant -- Department jurisdiction.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

91.

GAS

s3

Ct.D.P.U.C. 2002

[CONN.] Jurisdiction and powers -- State department -- Plant safety -- Liquified natural gas plant.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

92.

GAS

s5.1

Ct.D.P.U.C. 2002

[CONN.] Pipeline safety -- Replacement of cast iron and bare steel mains -- Accelerated replacement program -- Local distribution company.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

93.

VALUATION

s187

Ct.D.P.U.C. 2002

[CONN.] Capital expenditures -- Replacement of cast iron and bare steel mains -- Accelerated replacement program -- Natural gas local distribution company.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

94.

RATES

s307

Ct.D.P.U.C. 2002

[CONN.] Meter set installations -- Relocations and repairs -- Natural gas local distribution company.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

95.

SERVICE

s288

Ct.D.P.U.C. 2002

[CONN.] Meter set installations -- Relocations and repairs -- Cost responsibility -- Natural gas local distribution company.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

96.

GAS

s5.1

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[CONN.] Pipeline safety -- Meter set installations -- Local distribution company.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

97.

PAYMENT

s51

Ct.D.P.U.C. 2002

[CONN.] Enforcing payment -- Denial of service -- Termination notice -- Natural gas local distribution company.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

98.

INTERCORPORATE RELATIONS

s14.2

Ct.D.P.U.C. 2002

[CONN.] Transactions with affiliates -- Cost allocation -- Reporting requirements
-- Natural gas local distribution company.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

99.

APPORTIONMENT

s43

Ct.D.P.U.C. 2002

[CONN.] Joint expenses of affiliates -- Cost allocation -- Reporting requirements
-- Natural gas local distribution company.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

100.

EXPENSES, 83

Ct.D.P.U.C. 2002

[CONN.] Payments to affiliates -- Safeguard against cross-subsidization -- Pricing
of affiliate goods and services -- Asymmetric pricing -- Natural gas local
distribution company -- Discussion.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

101.

INTERCORPORATE RELATIONS

s14.2

Ct.D.P.U.C. 2002

[CONN.] Transactions with affiliates -- Natural gas local distribution company --
Safeguard against cross-subsidization -- Asymmetric pricing -- Discussion.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

102.

INTERCORPORATE RELATIONS

s14.2

Ct.D.P.U.C. 2002

[CONN.] Transactions with affiliates -- Propriety and management efficiency --
Natural gas local distribution company.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

103.

RATES

s235

Ct.D.P.U.C. 2002

[CONN.] Single-issue rate making -- Infrastructure expansion rate mechanism --
Natural gas local distribution company -- Dissent.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

104.

VALUATION

s281

Ct.D.P.U.C. 2002

[CONN.] Natural gas local distribution company -- System expansion projects --
Recognition between rate cases -- Infrastructure expansion rate mechanism --
Dissent.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

105.

SERVICE

s188

Ct.D.P.U.C. 2002

[CONN.] System expansion projects -- Burden of cost -- Infrastructure expansion rate mechanism -- Natural gas local distribution company -- Dissent.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

106.

AUTOMATIC ADJUSTMENT CLAUSES

s46

Ct.D.P.U.C. 2002

[CONN.] Plant-based adjustments -- System expansion projects -- Recognition between rate cases -- Infrastructure expansion rate mechanism -- Natural gas local distribution company -- Dissent.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

107.

RATES

s380

Ct.D.P.U.C. 2002

[CONN.] Natural gas rate design -- Special factors -- System expansion projects --
Recognition between rate cases -- Infrastructure expansion rate mechanism -- Local
distribution company -- Dissent.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

108.

EXPENSES

s125

Ct.D.P.U.C. 2002

[CONN.] Natural gas local distribution company -- System expansion projects --
Recognition between rate cases -- Infrastructure expansion rate mechanism --
Dissent.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

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215 P.U.R.4th 185, 2002 WL 554356 (Conn.D.P.U.C.)

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RETURN

s26.4

Ct.D.P.U.C. 2002

[CONN.] Reasonableness -- Sharing of excess earnings -- Annual variable sharing mechanism -- Natural gas local distribution company -- Dissent.

Re Yankee Gas Services Company

P.U.R. Headnote and Classification

110.

RETURN

s92

Ct.D.P.U.C. 2002

[CONN.] Natural gas local distribution company -- Sharing of excess earnings -- Annual variable sharing mechanism -- Natural gas local distribution company -- Dissent.

Re Yankee Gas Services Company

Before Goldberg, Downes, Arthur (dissenting), Betkoski, III, and Kelly, commissioners.

BY THE DEPARTMENT

EXECUTIVE SUMMARY

In its application dated July 24, 2001, the Yankee Gas Services Company requested approval from the Department of Public Utility Control of new rates designed to produce revenues, on an annualized and normalized basis, of \$411,547,000. The rate requested represented an increase of \$29,224,000 or 7.64% in excess of current rates. In this Decision, the Department determines that a decrease of \$4,006,000 or (1.25%) will allow Yankee to provide safe, adequate service at reasonable rates and still be able to attract needed capital. The Department approved a return on equity of 11% and a rate of return on rate base of 8.91%.

The Department grants a modified Infrastructure Expansion Rate Mechanism to address significant capital expenditures that will be made by Yankee subsequent to the rate year contained in its application. The IERM, as modified by the Department, allows the Company to annually petition the Department to reopen this rate case to address the rate recovery associated with system expansion projects that are completed between rate cases, as requested by the Company. However, to limit the risks that could be placed on ratepayers, the Department limits the applicability of the IERM to projects with a positive internal rate of return. Additionally, the Department requires that the IRR calculation include the total capital costs of a project, including capital costs and any costs currently classified by the company as system reliability, depreciation, tax-related, overhead and maintenance, overhead expenses, and other expenses associated with the expansion program. However, the Department did not approve including the proposed LNG facility plant as an IERM project because it is premature.

In this Decision, the Department approves an annual variable earnings sharing mechanism. This mechanism provides for a significant incentive for Yankee to achieve maximum synergy savings from its merger with Northeast Utilities, finances system expansion through the IERM, and yet limits the potential for excess earnings. Specifically, the annual variable earnings sharing mechanism shares earnings in the following fashion: for the year 2002, the first 100 basis points of earnings above the Company's allowed ROE are shared between shareholders and ratepayers on a 75%/25% basis, respectively. Above 100 basis points, earnings are shared 50%/50%. For the years ending 2003 and 2004, the first 50 basis points are shared between shareholders and ratepayers on a 75%/25% basis, with any earnings above that level shared 50%/50%. For the year 2005, all earnings in excess of the allowed ROE are shared 50%/50%.

The Company proposed a level of depreciation expense based on certain depreciation

rates and salvage values, and applied those assumptions to its proposed plant-in-service. While the Department found many conclusions and proposals regarding the Company's depreciation rates appropriate, the Department prescribes in this Decision an average life group procedure to group plant-in-service, in contrast to the equal life grouping method proposed by the Company. The net effect of adopting the average life group procedure, increasing the net salvage value on some accounts, and applying these assumptions to an adjusted plant-in-service level reduces the Company's proposed depreciation expense by \$6,004,544.

A Fuel Diversity Fund was also proposed by the Company at an expected expense level of \$3,200,000. The proposed fund is intended to encourage customers to utilize more efficient appliances than those often used with other sources. However, because the program is intended to encourage fuel switching from other competing fuel sources, the Department denied the Company's request to have ratepayers fund the program, reducing proposed revenue requirements by \$3.2 million.

The Company's filing reflected a certain level of synergies as a result of the merger between Northeast Utilities and Yankee Energy System, Inc. However, the Company simultaneously removed what it considers the shareholders' share of synergies from the baseline rate year revenue requirement (\$3,510,000). The Department disallowed the Company's rate year synergy adjustment because those proposed expenses do not reflect actual expenses that may or may not occur.

The Department significantly reduces the Company's proposed rate year gas cost from \$228,152,000 to \$167,300,000. The Company's request was based on year 2000 gas costs, which is a year that the Department considers anomalous. Therefore, the Department adjusts rate year gas costs to reflect the significant changes in the national gas market since the year 2000. After adjusting revenues for these changes to gas costs, the net effect of this adjustment on proposed revenue requirements is small.

DECISION

I. INTRODUCTION

A. BACKGROUND OF PROCEEDING

By application dated July 24, 2001 (Application), filed pursuant to the General Statutes of Connecticut (Conn. Gen. Stat.) §§ 16-19 and 16-19b, Yankee Gas Services Company (Yankee or Company) requested approval from the Department of Public Utility Control (Department or DPUC) of new and amended rate schedules. The proposed new rates were designed to produce revenues of \$411,547,000 on an annualized and

normalized basis, which is \$29,224,000 or 7.64% in excess of revenues being produced by the Company's present rate structure.

By letter dated October 17, 2000, the Department approved Yankee's request to bifurcate the rate proceeding into a revenue requirement phase (Phase I) and a cost of service/rate design phase (Phase II). As a result, any approved change in revenue requirements in this proceeding would be applied on a volumetric throughput basis until new rates are designed in Phase II.

B. CONDUCT OF THE PROCEEDING

By Notice of Hearing dated August 14, 2001, pursuant to Conn. Gen. Stat. §§ 16-19 and 16-19b, the Department held a public hearing on this matter on September 24 at its offices, Ten Franklin Square, New Britain, Connecticut and at 6:30 p.m. at the Waterbury City Hall, 235 Grand Street, Waterbury, Connecticut. The Hearing continued at the offices of the Department on September 26, 28; October 1, 2, 9, 10, 11, 15, 18, 19, 29, November 5, and 6, 2001. A hearing was held at 6:30 p.m. on October 2, 2001, at the New London Town Hall, 181 State Street, New London Connecticut. By Notice of Close of Hearing dated November 14, 2001, the hearing was closed.

C. PARTIES AND INTERVENORS

The Department recognized the following as parties to this proceeding: Yankee Gas Services Company, 107 Selden Street, Berlin, Connecticut 06037-1651; the Office of Consumer Counsel (OCC), Ten Franklin Square, New Britain, Connecticut 06051; and the Prosecutorial Division of the Department (PRO), Ten Franklin Square, New Britain, Connecticut 06051. The Department granted the Office of the Attorney General (AG) intervenor status in this proceeding.

D. PUBLIC COMMENT

On September 24, 2001, a hearing was held at the Department in which the Chairman of the panel accepted public comment. The First Selectman of East Lyme, Oxford, and Woodbury spoke in favor of Yankee's proposal based on the economic growth resulting from expanding natural gas service to the aforementioned cities. Citing new businesses, additional tax revenues, new residential customers, an alternative heating source, and safety concerns, the speakers were united in their support for natural gas service.

On September 24, 2001, a hearing was held at Waterbury City Hall at 6:30 PM for the purpose of taking public comment. No one attended this Public Comment Hearing. On October 2, 2001, a hearing was held at New London Town Hall at 6:30 PM for the purpose of taking public comment. No one attended this Public Comment Hearing.

II. DEPARTMENT ANALYSIS

Yankee's rates were last set in a full rate case in 1992 in the Decision dated August 26, 1992 in Docket No. 92-02-19, Application of Yankee Gas Services Company for an Increase in Rates. Four years later pursuant to Conn. Gen. Stat. §16-19a, the Department conducted a financial and operation review of the Company. See, Decision dated July 9, 1997 in Docket No. 96-08-05, DPUC Financial and Operational Review of Yankee Gas Services Company. Subsequently, the Department approved a merger between Yankee and NU in the Decision dated December 29, 1999 in Docket No. 99-08-02, Joint Application of Northeast Utilities and Yankee Energy Systems, Inc., for Approval of a Change of Control.

In the latter Decision, the Department ordered Yankee to provide the projected merger synergies identifying the source of all regulated and unregulated savings. See, Decision, Order No. 11. The identified estimated cost savings associated with the merger were to be reviewed in its next rate case, which is the instant docket. In addition to synergy savings, the Company is currently overearning as shown by their filings under Docket No. 76-03-07, Investigation to Consider Rate Adjustment Procedures and Mechanism Appropriate to Charge or Reimburse the Consumer for Changes in the Cost of Fossil Fuel and/or Purchased Gas for Electric and Gas Public Service Companies. In Yankee's last quarterly report dated November 21, 2001 for the 12-months ended September 30, 2001, the Company earned 12.65%. This is 150 basis points above its allowed return on equity (ROE) of 11.15%. It is in this context that the Department reviewed the Company's request for a \$29 million increase.

A. TEST YEAR/RATE YEAR

[1] It is the practice of the Department in utility rate cases to establish rates prospectively upon the basis of a historical test year, adjusted for pro forma purposes. In this case, the Yankee used the operating results for the 12 months ended September 30, 2000 as its test year. The Department will accept this time period as the test year. Historically, the Company has adjusted its test year to reflect its rate base and capital structure to the midpoint of the rate year (i.e.,

the year that rates will be in effect). The Company's rate year is the calendar year beginning on January 1, 2002, and ending on December 31, 2002. Additionally, revenues were adjusted for forecast-year customers and certain expenses were adjusted for known changes. The Company also applied an inflation factor to those expenses that were not specifically adjusted elsewhere.

B. RATE BASE

[2] Yankee calculated its rate base as of the midpoint of its proposed rate year. Thus, the rate base consists of the average, depreciated cost of the Company's plant-in-service as of June 30, 2002, determined by averaging the beginning and ending rate year balances. The rate base also includes a working capital allowance, prepayments including insurance, inventory and property taxes, regulatory assets and deferred expenses. The Company's rate base is reduced by items such as accumulated deferred income taxes, uncollectibles reserve, customer's advances for construction, customer deposits and regulatory liabilities.

1. Accumulated Depreciation

[3] In Section II.D.5. Depreciation Expense, the Department made adjustments to the Company's proposed level of depreciation expense for the rate year and reduced this expense by \$6,004,544. Since the appropriate level of accumulated depreciation for the rate year includes depreciation expense through the midpoint of the rate year, the level must be correspondingly reduced by one half that amount or \$3,002,272.

2. Deferred Income Taxes

[4] In Section II.D.15.c. Deferred Federal Income Taxes, the Department made adjustments to the Company's proposed level of deferred federal income tax expenses for the rate year and increased this expense by \$2,184,318. Since the appropriate level of deferred income taxes in the rate year rate base includes deferred federal income tax expenses through the midpoint of the rate year, the level must be correspondingly increased by one half that amount or \$1,092,159.

3. Working Capital

a. Background

[5, 6] It is customary regulatory practice to allow an adjustment to rate base in recognition of the timing differences between when revenues are received and when expenses are paid out. Also, an adjustment is required to account for the need to have such items as fuel and materials and supplies on hand and available prior to actually being needed. It is the Department's preference that timing differences between revenues and expenses be determined by means of a lead/lag study rather than using some rule of thumb approach.

The Company provided such a study for the 12 months ending September 30, 2000. Schedule H-1.6. To better reflect the situation that would likely exist in the rate year due to the Company's recent merger with Northeast Utilities System (NU), Yankee used the results of its lead/lag study for The Connecticut Light and Power Company (CL&P) in some instances. In addition to a request for a working capital allowance based on the results of its lead/lag study (cash working capital), the Company requested an allowance for propane fuel, and materials and supplies, excluding fuel. The Department has reviewed the Company's request for a working capital allowance and finds it acceptable except as noted below.

b. Cash Working Capital

OCC recommends a number of adjustments to the Company's cash working capital proposal. OCC claims that the Company: 1) did not adequately reflect the check-clearing lag in its calculation of the other O&M expense lag; 2) included non-cash items such as depreciation and deferred taxes in the study; 3) accounted for the prepayment of property taxes twice, once in the lead/lag study and again as a prepayment, and 4) made an error in the calculation of the purchased gas lag. Brief, pp. 23-26. The Company agrees with OCC claims 3) and 4) and concedes that the cash working capital allowance should be adjusted for these errors. Tr. 10/19/01, pp. 2540-2542. To adjust for these errors, the Department has removed property taxes from prepayments in rate base (see, Section II.B.5.d. Property Taxes) and recalculated the Company's lead/lag study result using the corrected purchased gas lag of 37.42 days in place of the 12.17 days used in the study. Response to Interrogatory OCC-405.

The Company takes exception to OCC claims numbers 1) and 2). Reply Brief, pp. 26 and 27; Schedule H-1.6, p. 5. With regard to claim 1), the Company believes that its approach is even-handed in that it ignored the check-clearing lag on both sides of the lead/lag equation, revenues and expenses. Tr. 10/19/01, pp. 2546-2548. The Department agrees that the Company has not necessarily inflated the result of its

lead/lag study by this omission. The check-clearing lag is likely to be larger in the case of Company expenses that are paid by check since the lag would also include the delivery of the check to vendors (not the case when the Company receives a check). It is also likely to be the case that a smaller percentage of expenses are paid by check than revenues rendered to the Company. As such the Department will not make an adjustment for the omission of the check-clearing lag. With regard to the inclusion of non-cash items in the study, the Department believes that these items need to be considered because the expenses have a rate base impact associated with them. OCC acknowledges that as these expenses are booked they result in an offset to rate base. Tr. 10,18/01, pp. 2351-2354. As such, their inclusion in the study is appropriate to avoid displacing rate base with funds that have not yet been received by the Company.

In addition to the various leads or lags associated with expense and revenue categories, a cash working capital allowance also depends on the weighting of each category and the total expense level involved. The Company's proposal is based on the weighting of categories from the study, the 12-months ending September 30, 2000, and the total expense level of its revenue requirement request. Based on this, the Department also adjusted the cash working capital allowance to correspond to the allowed rate year amounts in this Decision. The aggregate result of the above-noted adjustments to the Company's proposal is to reduce the cash working capital allowance by \$16,272,000 from \$25,636,000 to \$9,364,000.

4. Plant Additions

[7, 8] According to the Company, the capital expenditures for 2001 are \$59.9 million. The Company proposed a pro forma increase of \$30.2 million, for a total of \$90.1 million in the rate year. This increase to the rate base is mostly the result of capital expenditures associated with projects under the Company's proposed Infrastructure Expansion Rate Mechanism (IERM). The Company made a number of adjustments to the test year rate base based on certain assumptions. Plant-in-service incurred between September 30, 2000 and December 31, 2000, along with their respective construction work-in-progress balance as of December 31, 2000, were assumed to be 100% complete and in-service. The Company stated that it used the historic trend of 46% to determine its assumptions for capital expenditures to be added to rate base. Therefore, the Company assumed that of the \$59.9 million in capital expenditures in 2001, approximately 46% would be in-service at the beginning of the rate year and 100% in-service at the end of the rate year. These would be included in rate base. Additionally, the Company assumed that 46% of the entire \$90.1 million of capital expenditures that it assumed to be in-service at the end of the rate year, would be included in rate base. This results in an addition of \$42 million of capital expenditures, being added to rate base for calendar year 2002. Mahoney PFT, pp. 6 and 7.

OCC believes that there should be certain adjustments to Yankee's original Application for projects that are committed in year 2001. Specifically, a reduction in pro forma plant-in-service of \$410,537,699, a decrease in depreciation expense of \$445,000, a related decrease in depreciation reserve of \$222,500 ($\$445,000 * 50\%$), and an increase in net margin of \$355,000. Further, OCC opposes any request to include plant in rate base for projects that are planned to occur in 2002 that have not been publicly announced to date. OCC also believes that the remaining announced projects, rolled into the rate base for the 2002 rate year, are speculative in nature and that there are no signed contracts for service. OCC supports this conclusion by citing that Yankee has not filed for the necessary permits or has not begun construction on these facilities. Additionally, it is inappropriate to include these projects in the rate base since the Company has not included the associated revenues in the instant docket. Brief, pp. 38 and 39.

The Department accepts the Company's proposed plant-in-service of \$42 million in rate year-end rate base. The Department is aware that a significant portion of this capital expenditure is the result of projects contained in the proposed IERM program. The Department will conditionally allow the inclusion of the Company's proposed \$42 million of capital expenses in rate base, based on a successful review of each and every project under the IERM program. The Department will review all projects contained within the IERM as described in Section II.I. System Expansion in this Decision.

5. Prepayments

[9] For the prepaid accounts listed below, the Company used an average of the December 31, 2001 and December 31, 2002 account balances to arrive at the rate year prepaid balance at mid-year. Schedule B-1.0; Schedule B-5.0.

a. DPUC Assessment

The Company requested a prepaid DPUC Assessment balance of \$239,000 in its filing. Schedule B-5.0. The Department notes that the test year average balance is \$85,493. However, the test year average is not representative of normal activity in the account as the months of October through December 1999 have no balance, and January 2000 has a negative balance of \$72,979. Late Filed Exhibit No. 124.

To determine a reasonable prepaid balance for the assessment, the Department used the Company's most recent invoice and determined that the Company would make quarterly payments aggregating \$1,044,943 for the period July 1, 2001, through June 30, 2002. Late Filed Exhibit No. 93, pp. 2 and 3. The highest balance at the start of a quarter would be \$261,235 (\$1,044,943 divided by 4). At the halfway point of the quarterly amortization, the prepaid balance would be \$130,618 (\$261,235 divided by two). Accordingly, the Department reduces the Company's proposed prepaid DPUC Assessment balance by \$108,382 (\$239,000 minus \$130,618).

b. Insurance

The Company proposed a prepaid insurance balance of \$413,000. Schedule B-5.0. The Department notes that the average test year balance in this account is \$355,000. Late Filed Exhibit No. 124. Further, the Department is aware of a \$317,000 annual premium reduction in the Public Liability Injuries and Damages account, or an average of \$26,000 per month. Response to GA-ADR 9. The Department prefers use of the annual test year average balance adjusted by the known average premium reduction. Accordingly, the Department allows \$329,000 as the prepaid insurance balance for the rate year (\$355,000 minus \$26,000) and reduces the proposed prepaid insurance balance by \$84,000 (\$413,000 minus \$329,000).

c. Inventory

In its Application, Yankee reflected \$17,968,000 as its rate year prepaid storage inventory balance. The Company's estimate is based on the September 30, 2000, inventory balance of \$16,782,000 that escalates to \$18,019,000 through December 31, 2002. Schedule B-5.0.

OCC indicated that historical changes in the volume of gas maintained in storage on hand on a month-to-month basis shows that increases in storage inventory occurred from May to October. This results in relatively high inventory volumes on September 30 and December 31. In OCC's opinion, use of an estimated point in time is inappropriate to cost inventory. Rather, an average balance is typically used to represent an annual prepaid level. OCC recommends the use of the average test year inventory value of approximately \$7,645,000. Schultz and DeRonne PFT, pp. 9-11.

The Department agrees with OCC that use of an annual average is preferable to using inventory values determined at a single point in time. Accordingly, the Department accepts OCC's recommendation and the average test year inventory value of \$7,645,000 as being representative of prepaid inventory. Consequently, the Department reduces

the proposed prepaid inventory balance by \$10,323,000.

d. Property Taxes

The Company proposed a rate year prepaid property tax balance of \$750,000. Schedule B-5.0. As discussed above, the Company concedes that the allowance for cash working capital includes recognition of the prepaid nature of property taxes. As such, a separate prepayment balance is not required for property taxes. The Department will reduce the proposed prepaid property tax balance by \$750,000 to zero.

e. Summary

The following summarizes the Department's rate base adjustments for prepayments:

1. Insurance	\$ (84,000)
2. DPUC Assessment	(108,382)
3. Inventory	(10,323,000)
4. Property Taxes	(750,000)

Total Rate Base Adjustment for Prepayments \$ (11,265,382)

6. Regulatory Pension Liability

[10] Due to the NU/Yankee merger the pension obligation was adjusted to reflect the fair value of the pension obligation on March 1, 2000 for a regulatory pension liability of \$39,253,000. The fair value of the pension plan assets exceeded the projected benefit obligation by \$39.3 million, which resulted in the recognition of a deferred debit. The recognition of this \$39.3 million did not affect the net periodic pension credit at March 1, 2000 due to a corresponding regulatory liability that was recorded for the same amount. In addition, if the NU merger had not taken place this amortization would have been included in the actuary's calculation of the net periodic pension credit. Mahoney PFT, p. 13. This is recorded as a debit to prepaid pensions with the offsetting credit booked as a deferred regulatory liability. It is to be amortized over 15.82 years as a credit to pension expense resulting in annual amortization expense of a negative \$2.5 million. Mahoney PFT, p. 13; Response to Interrogatory OCC-50. This credit to pension expense is going to be flowed back to ratepayers, which in effect is a reduction to expense over a 15.82-year period. Mahoney PFT, p. 13.

OCC believes that an adjustment to rate base must be made to the approximate \$39,000,000 of previously unrecognized items for pensions as part of the recording of the recent merger with NU. Brief, p. 26. OCC recommends that Yankee's rate base be reduced by \$38,012,000 and to reflect a return to ratepayers on this amount. Schultz and DeRonne PFT, pp. 19 and 20.

The AG asserts that Yankee acknowledged that approximately \$39 million of overfunded pension liabilities will be amortized and used to reduce revenue requirements over the next 15 years. However, the AG notes that Yankee has not made an adjustment to its rate base to account for this overfunding. The AG believes that ratepayers are entitled to have the average rate year balance of overfunded pension of approximately \$38 million removed from rate base during the test year. The AG asserts that these pension funds should be removed from rate base, which will reduce revenue requirements, by \$5.3 million a year. Brief pp. 13 and 14.

The Department believes that the OCC and AG are incorrect in their argument to adjust Yankee's rate base for the regulatory pension liability. The Department finds that the Company has not received cash from ratepayers but that this is an accounting entry due to the merger with NU. Tr. 10/18/01, p. 2384. During cross-examination, OCC admitted that the Company cannot utilize this cash and receives no time value of money benefit from it. Tr. 10/18/01, p. 2384. In addition, OCC agreed that there is a difference between a Company receiving cash that it can utilize in its business versus as in this case, in which a pension fund receives a payment that it invests on behalf of the pension plan participants where Yankee has no access to these funds. Tr. 10/18/01, p. 2423. This \$39.3 million is working for Yankee's pension plan participants by earning a return, which is a component of the actuary's determination of pension expense. The Department believes that since the Company is not utilizing these funds for corporate purposes that they should not be adjusted in rate base.

7. Reserves

a. FAS 106 Unamortized Balance

[11, 12] In its initial filing Yankee requested the amortization of the regulatory asset that was created as a result of prior Financial Accounting Standards No. 106 (FAS 106) expenses that exceeded the allowed annual level of \$1.7 million. As of December 31, 2001, the regulatory asset is projected to be \$3.5 million and Yankee is proposing to amortize this over four years equating to an annual amortization expense of approximately \$900,000. Mahoney PFT, p. 12. Yankee included this unamortized deferred FAS 106 balance in rate base, Schedule B-1.0., revising the

unamortized balance for FAS 106 to \$2,821,515. Late Filed Exhibit No. 71.

Yankee states it chose a four-year period for two reasons: to avoid creating a spike in the revenue requirement, which would occur if the amortization was for only one year, and to avoid a recovery period that was too long because this approach can create difficult situations in the future if the total regulatory asset balances continue to grow rather than decrease. In addition, Yankee also wanted to use a recovery period that closely approximated the amount of time between rate proceedings, which is generally three to four years. A four-year amortization period provides Yankee with a reasonable time for recovery of the FAS 106 asset and maximizes the opportunity to complete the amortization at approximately the same time that the next rate proceeding will probably take place. Response to Interrogatory OCC-14.

OCC asserts that the new FAS 106 balance of \$2,821,515 should be used to calculate the amount included in rate base, which equates to a reduction in rate base of \$571,175. OCC further states that Yankee agreed to the validity of this adjustment during cross-examination. Brief, pp. 28 and 29. No other party or intervenor briefed this issue.

After reviewing the transcript, the Department believes that Yankee agreed to the validity of OCC's adjustment to rate base. Tr. 11/5/01, p. 3087. The Department used the revised deferred and unrecovered FAS 106 balance of \$2,821,515 at the start of the rate year, January 1, 2002. Late Filed Exhibit No. 71. This represents a \$652,485 reduction below the \$3,474,000 as shown in Yankee's rate base summary for January 1, 2002. Yankee requested a four-year amortization of the original beginning rate year amount of \$3,474,000, which is \$868,500 annually. Using this \$868,500 annual amortization, Yankee forecasted an average/ midpoint of the rate year level of \$3,039,750 $[(\$3,474,000 + (\$3,474,000 - 868,500))/2]$ for the deferred FAS 106 expense. Using the revised deferred balance at the start of the rate year of \$2,821,515, the Department calculates an annual amortization of \$705,379. The Department calculates this to equate to an average rate year deferred balance of \$2,468,825 $[(\$2,821,515 + (\$2,821,515 - 705,379))/2]$. This is a reduction to rate base in Yankee's deferred unamortized FAS 106 balance of \$571,175 $(\$3,040,000 - 2,468,825)$.

b. Supplemental Employee Retirement Plan

[13] Yankee includes in its benefit package to executives a supplemental employee retirement plan (SERP) in addition to the general retirement plan. The purpose is to provide certain executives with a supplemental retirement benefit in addition to the

benefit provided under the NU Retirement Plan (Retirement Plan). The SERP provides the benefits that would have been provided to the eligible executives under the Retirement Plan if incentive compensation and benefits were not subject to the limitations imposed by Sections 401(a) (17) and 415 of the Internal Revenue Code. Response to Interrogatory OCC-181.

OCC recommends that Yankee's rate base be reduced by \$1,582,577 for the deferred credit amount associated with the SERP. Schultz and DeRonne PFT, pp. 20 and 21; Schedule B. It argues that SERP is an extra benefit payable to a select group of executives in addition to the Retirement Plan already in revenue requirements. This extra benefit is not deductible for income tax purposes. Therefore, ratepayers effectively fund this extra benefit expense in advance without receiving any reduction in taxes for it and have not been provided a credit for the advance. Based on history, Yankee has expensed a higher amount than the annual level of payout. The result of this cumulative accrual is the \$1,582,577 deferred credit at the end of the test year. Mr. Schultz and Ms. DeRonne believe that this advanced funding by ratepayers needs to be reflected as an offset to rate base. Schultz and DeRonne PFT, pp. 20 and 21. In its brief, OCC reiterated the need for a reduction in rate base by \$1,582,577 for the deferred credit amount associated with the SERP to recognize these cost free funds provided to Yankee by ratepayers. Brief, p. 28. The other parties and intervenors were silent on this issue.

The Department concurs recognizing that the SERP is an extra benefit payable to a select group of executives above and beyond the retirement plan already in revenue requirements. This extra benefit is not deductible for income tax purposes. Therefore, ratepayers effectively fund this extra benefit expense in advance without receiving any reduction in taxes for it and have not been provided a credit for the advance. Late Filed Exhibit No. 123. The advance funding by ratepayers is due to accrual accounting, whereby Yankee will accrue the SERP expense each year and set up a liability for payment of that expense years later when the executive retires. On a historical basis Yankee has expensed a higher amount than the annual level of payout, which has resulted in a deferred credit on Yankee's books of \$1,582,577 associated with the SERP. This deferred credit is the difference between the amounts expensed and effectively collected from ratepayers each year and the amount Yankee actually pays out. During cross-examination, a Yankee witness verified that Yankee has the use of the excess funding of the SERP until it is paid out. Tr. 10/11/01, p. 1674. In recognition of this advance funding by ratepayers, the Department decreases Yankee's rate base by \$1,582,577.

c. Uncollectibles

[14] In Section II.D.17.b. Uncollectible Accounts Receivable Expense, the

Department identified changes to Yankee's uncollectible expenses for the rate year of \$1,878,528. Accordingly, the Department reduces the Company's reserve for uncollectibles by \$939,264. This represents the effect on the uncollectible reserve halfway through the rate year.

8. Sale of Land in Bethel

[15, 16] In its rate proposal, Yankee did not provide for gain or loss on disposal of utility plant, net. Schedule C-1.0, line 27. In the Decision dated February 14, 2001 in Docket No. 98-12-07RE01, Application of Yankee Gas Services Company for the Approval of the Sale of Property in Bethel, Connecticut -- Phase I -- Amended Consideration, pp. 2 and 4. a previous Decision, the Department approved the sale of that property for the consideration of \$3,600,000.

The Bethel land sale was expected to close in December 2001 or the first quarter of 2002. Response to Interrogatory GA-160. Yankee provided the sale's financial impact as if the sale closed on March 31, 2002, as follows:

1. Net Rate Base Impact (decrease)	(\$ 404,000)
2. Depreciation Expense	(36,000)
3. Property Tax	(48,000)
4. Income Tax Expense	34,000
5. Net Amortization of Gain on Disposal Of Utility Plant	(332,000)

Late Filed Exhibit No. 89

OCC agrees that the adjustments to the Company's original Application should be adjusted by the amounts indicated in Late Filed Exhibit No. 89. Further, OCC requested that the Department consider flowing the pre-tax amortization amount of \$544,936 in its calculation of the Company's revenue requirement. Brief, p. 65.

The Department's calculation of the net effect of amortization of the after-tax gain, rather than using the pre-tax amortization amount, is consistent with Department precedents, and results in the proper reflection of revenue requirements. See, Decision dated March 14, 2001 in Docket No. 99-09- 03RE02, Application of Connecticut Natural Gas Corporation for a Rate Increase, Phase 1 -- Gain on Condemnation, pp. 8 and 9. The Department accepts the Company's Late Filed adjustments above, and will revise revenue requirements accordingly.

9. Transition Credit True-up

[17] In the Decision dated July 8, 1994 in Docket No. 94-01-12, DPUC Generic Review of Connecticut Gas Local Distribution Companies Implementation of the Federal Energy Regulatory Commission (FERC) Order No. 636, the Department addressed the payment of transition costs incurred due to the unbundling of interstate pipeline services in accordance with FERC Order No. 636. In that Decision, the Department approved the use of 100% of the capacity release, deferred gas costs and pipeline refunds and 75% of off-system sales and interruptible excess margin credits toward payment of transition costs by establishing a transition credit account. Subsequently, in the Decision dated January 3, 1996 in Docket No. 92-02-19 -- Reopen II, the Department approved the September 11, 1995 Stipulation and Agreement between the Company and OCC that increased the percentage of off-system sales and interruptible excess margin credits applicable to transition credits from 75% to 80%. Also, in the Stipulation and Agreement, the Company was allowed to apply transition credits to eliminate or reduce the following deferred expenses:

1. Natural Gas Vehicle Program;
2. Economic Development Activities;
3. Conservation Program;
4. Compliance with FASB Statement No. 106, 'Employers Accounting for Certain Post Retirement Benefits Other Than Pensions;' and
5. Hardship Accounts and Matching Payment Program.

Stipulation and Agreement, pp. 2 and 3.

In Docket No. 92-02-19, the Department extended the effective term of the Stipulation and Agreement aforementioned through September 30, 2000, and added 1997 Deferred Gas Costs to the affected deferred expenses. See, Decision dated October 1, 1997, p. 2. In the second quarter of 2001, the Company recorded a true-up to the transition credits of \$1,045,000. Response to Interrogatory GA-114. The true-up results in reductions to rate year deferred assets and amortization expenses.

OCC recommends adjustments to deferred asset amortization expense of \$261,000 and a rate base reduction of \$1,045,000 based on the Company's submission. Brief, p. 72.

The Department notes that \$1,045,000 represents the gross amount of the true-up adjustment which must be amortized and tax affected to properly reflect the rate base adjustment. Accordingly, the Department reduces deferred assets rate base by \$499,000, which represents the true-up net of tax and amortization. Schedule B-6.0 and Response to Interrogatory GA-379. To effectuate the adjustment to amortization expense, the Department reduces the \$1,045,000 amount by \$96,000 representing transition credits related to FAS 106 that are adjusted separately in Section II.B.7. The Department then divides the net amount of \$949,000 (\$1,045,000 less \$96,000) over four years which reduces the deferred assets' amortization expense by approximately \$237,000 (\$949,000/4). Late Filed Exhibit No. 85.

C. REVENUE ADJUSTMENTS

The Company states that the actual test year revenues, including Purchased Gas Adjustment (PGA) revenues, totaled \$307,447,000. Test year pro forma adjustments reflecting annualized customers, normalized weather, PGA roll-in and other non-recurring revenues totaled (\$9,969,000) plus rate year adjustments of \$84,845,000 resulted in total rate year revenues of \$382,323,000. Schedule C-2.0.

1. Pro Forma Adjustments

a. Normalizing Sales Revenue

[18] In determining pro forma revenues in the instant proceeding, Yankee uses weather data from Bradley Field (Bradley) to calculate normal weather. This data is based on the 20-year heating degree-day (HDD) period from 1981 through 2000. Blakey PFT, pp. 5 and 6. In previous rate cases, Yankee used the National Oceanic and Atmospheric Administration (NOAA) [FN1] 30-year normal, based on data from 1961 through 1990, when developing its sales forecasts. The NOAA officially issued data for the 30-year period 1971 through 2000 will not be available until the fall of 2001, according to Yankee. As the available data is outdated, Yankee chose the most recent 20-year period based on results of a survey conducted by NU, Yankee's parent company. Survey results indicate that the average number of years used to define normal weather by survey respondents was 19.2 years, which Yankee rounded to 20 years. In addition, Yankee believes that using a 30-year period to define normal weather does not adequately weight recent weather trends that indicate warmer weather. Yankee argues that using a normal based on a 30-year average would

over-estimate heating requirements in the winter and under-estimate cooling requirements in the summer because the average temperature in the Northeast is gradually rising. Response to Interrogatory GA-342; Tr. 10/12/01, pp. 1913 and 1914.

The Company provided a comparison between the total test-year actual HDD with the 30-year average from 1971 to 2000, and Yankee's proposed 20-year average from 1981 to 2000, as stated below.

Actual HDD	30-year HDD	Yankee 20-year HDD
Test-year	1971-2000	1981-2000
5,756	6,066	5,968

Response to Interrogatory OCC-104.

Further, the Company provided the following table that shows the additional sales and revenue that result from the use of the 30-year monthly issued NOAA data rather than the 20-year period used by Yankee.

Rate	Sales (Mcf)	Revenue
Rate 2	155,774	\$1,400,873
Rate 10	65,834	\$502,174
Rate 26	98	\$423
Rate 27	3,329	\$12,930
FTS-1	28,220	\$1,326
FTS-2	60,450	\$171,422
FTS-3	1,295	\$5,037
TOTAL	315,000	\$2,094,187

Response to Interrogatory OCC-313.

OCC opposes using the most recent 20 years of heating degree-days to calculate normal weather sales, and recommends using the most recent 30-year period. Although OCC understands Yankee's objection to using NOAA 30-year data that is outdated, it disagrees with the Company's use of a 20-year period. OCC believes that the Company should use contemporary data to determine the normalized annual consumption. Further, OCC believes that the sample size (i.e. number of years) is equally important as using contemporary data when determining the annual normalized consumption. Moreover, OCC states that the NOAA-issued data has a sufficient sample size, so that its data has a greater reliability than the Company's 20-year normal. Cotton PFT, p. 17. Further, OCC contends that data used by NOAA is official, and is

used, approved and maintained by the federal government. Brief, p. 82. However, OCC states that the 30-year NOAA normal is only officially updated at the end of every decade. Since NOAA's updated report for 1971-2000 has not yet been issued, OCC recommends using the most recent 30 years of NOAA-issued monthly data, from 1971 through 2000 to normalize revenues. Cotton PFT, p. 17.

The Department believes that the Company's data shows that the actual weather for the test-year period was warmer than normal as defined by the current 30- year and 20-year average. However, the Department believes the difference between the 20-year and 30-year normalized HDD is not excessive. The 30-year normal is only 98 HDDs higher than the 20-year normal. Currently, Department policy for Connecticut LDCs is to use a 30-year degree-day period for calculating normal weather. Yankee and The Southern Connecticut Gas Company (Southern) use the officially issued NOAA report, [FN2] while Connecticut Natural Gas Corporation (CNG) uses NOAA monthly-issued data. Further, the official NOAA data uses a 30-year normal weather period. As such, the Department believes that the use of 30 years of data rather than 20 years to define normal weather is appropriate. Since the updated NOAA 30-year report for the period 1971 through 2000 is unavailable at this time, the Department concurs with OCC's recommendation to use the most recent 30 years of monthly-issued data. For the purposes of this filing, NOAA monthly-issued data from the period 1971-2000 will be used to normalize pro forma revenue. The Department also believes that using monthly NOAA data will allow the Company to use current weather data when developing forecasts in the future. The Department believes that since the sales forecast will increase proposed rate year revenues, the Department will adjust the rate year revenues. Therefore, the Department increases the Company's pro forma revenue by \$2,094,187 to account for the adjustment to the normalized HDD.

b. New Customers

[19] Yankee provided an update to the number of large firm and interruptible customers with anticipated annual consumption of greater than 5,000 Mcf that either came on-line since the sales forecast was developed, or are expected to come on-line during the rate year. The Company states that the additional customers are a result of Yankee's system expansion program. The following table shows by rate class the expected sales and revenue associated with the expansion program, which are not included in the Company's original forecast. Yankee provided an update to the number of large firm and interruptible customers with anticipated annual consumption of greater than 5,000 Mcf that either came on-line since the sales forecast was developed, or are expected to come on-line during the rate year. The Company states that the additional customers are a result of Yankee's system expansion program. The following table shows by rate class the expected sales and revenue associated with the expansion program, which are not included in the Company's original forecast.

Rate	Sales (Mcf)	Revenue
Rate 2	60,359	\$ 837,663
Rate 10	236,208	2,727,495
Rate IS	56,644	648,056
TOTAL	<u>353,211</u>	<u>\$ 4,213,214</u>

Response to Interrogatory GA-350 SP01.

The Department believes that since these customers have already received service or are expected to receive service during the rate year, revenues associated with those customers should be included in the rate year revenues. Consequently, the Department increases pro forma revenue by \$4,213,214.

c. Service Contract Work

[20] Yankee's original filing shows an appliance contract test year revenue of \$1,182,000 with a pro forma adjustment of \$118,000. This equated to total rate year revenue of \$1,300,000. Schedule C-3.16. Subsequently, Yankee increased the test year revenue by \$58,000 to \$1,358,000 and projected no pro forma adjustments. This resulted in a rate year revenue equivalent to the revised test year revenue of \$1,358,000. Tr. 10/12/01, pp. 1759; Late Filed Exhibit No. 78.

Due to Yankee's change to its appliance contract revenue, the Department increases Yankee's pro forma revenue by \$58,000.

d. Conclusion

As a result of the pro forma revenue adjustments described above, the Department increases Yankee's pro forma revenue by \$6,365,401 (\$2,094,187 + \$4,213,214 + \$58,000). As discussed in Section II.F. Gas Cost, the Department decreased the pro forma adjustment to the purchased gas expense. To correspond with that adjustment, the Department decreases pro forma revenues by \$66,990,579, which have been adjusted for the gross revenue tax. This amount is calculated by taking the difference between the total gas costs proposed by the Company (\$228,152,000), including additional sales pro formed by the Department (\$953,000 plus \$2,658,000), and the amount allowed by the Decision (\$167,300,000) and adjusting that difference for the gross revenue tax. The total adjustments decrease pro forma operating revenues by \$60,625,178.

2. Billable Appliance Services

[21-23] Yankee offers a variety of gas appliance repair services to its customers on a billable hourly basis (billable service) or through its Advantage Protection Service Plan contracts. Gas appliance repair services are a competitive service, which are provided to all residential customers and certain commercial customers who have residential equipment. Many customers utilize these services but do not sign up for a service contract. Billable services for customer-owned residential gas appliances such as ranges, water heaters, space heaters, clothes dryers and central heating units are charged on an hourly basis, plus the cost of parts. The current pricing structure for billable services was approved in Docket No. 88-08-35, Application of The Connecticut Light and Power Company for Approval to Revise Meter and Service Policies Concerning Customer-Owned Appliances. However, these rates no longer generate sufficient revenue to recover the cost of providing such services. Beschler PFT, pp. 15 and 20. Tr. 10/12/01, pp. 1790-1791. The current billable service pricing structure is as follows:

	One Employee	Two Employees
Mon.-Fri. 8:30-4:30 p.m.	\$23.50 per hour for the first 1/4 hour or fraction \$9.50 for each additional 1/4 hour or fraction	\$35.00 per hour for the first 1/4 hour or fraction \$9.50 for each additional 1/4 hour or fraction
Emergency work after regular hours,	\$35.00 per hour for the first 1/4 hour or fraction	\$49.00 per hour for the first 1/4 hour or fraction
weekends, holidays	\$14.00 per hour for each additional 1/4 hour or fraction	\$14.00 per hour for each additional 1/4 hour or fraction

Beschler PFT, p. 15.

To recover the appropriate costs of providing these services, Yankee is proposing two types of changes to its billable services pricing structure. First, the Company is proposing a flat rate pricing scheme for the majority of billable services. For all other billable services, the Company is proposing to increase hourly labor rates. Beschler PFT, p. 16. Yankee also requests that any future changes to billable service rates be filed with the Department 10 days prior to the effective date, the same as CNG. It is the Company's long-term intention to develop a flat rate pricing structure for all appliance repair work. Response to Interrogatory GA-223. Each proposal is discussed in more detail below.

a. Flat Rate Pricing

Flat rate pricing combines the hourly labor and the materials typically used for each job into one price or 'flat rate.' Yankee developed a price list for the majority of appliance repair services that it believes should be priced at a flat rate. The flat rate pricing structure includes a minimum diagnostic fee for a service person to visit the customer's premises with additional charges for work performed. Depending on the type of repairs the additional charges would be a fixed price that would include the cost of labor as well as materials.

An example of a typical flat rate service charge would be the replacement of a hot air furnace thermostat. The Company states that under the proposed flat rate pricing, the minimum charge would be the \$35.00 diagnostic fee for a visit to the customer's house during normal working hours with an additional charge of \$65.00 for labor and parts. The total cost to replace the thermostat would be \$100.00 plus tax, no matter how long the job takes. Beschler PFT, pp. 17 and 19. Under the Company's proposed billable service rates, the total cost to replace a thermostat would range between \$45.00 to \$193.00, depending on how long it takes to complete the job. Beschler PFT, pp. 16 and 17; Late Filed Exhibit No. 83SP01.

To determine the proposed flat rates for each service performed under this pricing structure, Yankee extracted samples from its records of actual work performed for a specific activity. It then reviewed the cost of the materials and the amount of time it took to complete. Each sample activity was then priced at the proposed billable service rates plus the projected cost of the materials. The mean of each sampled activity was calculated and a 99% confidence interval calculation was performed on the resulting mean. From this analysis, the Company was able to determine which activities are appropriate for flat rate pricing based on the confidence interval and sampling size. For certain activities performed infrequently, such as gas fireplace inspections and adjustments, water heater replacements and pool heater cleaning and servicing, the Company does not have enough data to support a valid statistical analysis to determine a flat rate price. Consequently, the Company left these activities on the hourly billable rate structure until a larger sample size becomes available. Beschler PFT, pp. 17 and 18. Response to Interrogatory OCC-231.

The Company states that flat rate pricing for service work is not common in the gas utility industry, nor is it common for plumbing or electrical service work. Response to Interrogatory GA-317; Tr. 10/12/01, p. 1768. However, Yankee believes that this type of pricing structure would provide customers with 'a sense of comfort' in the knowledge of paying a set price for the requested service. Response to Interrogatory GA-317. The customer may also opt to have other service work done during the same service call for the single diagnostic fee. Id. In addition, the Company states

that a flat rate would allow customers to 'shop around' for prices. Tr. 10/12/01, p. 1769. The Company would also benefit from flat rate pricing as it would eliminate call center representative price estimates, minimize bill adjustments, streamline paperwork, and simplify the explanation of services provided to the customers. Yankee also testified that flat rate pricing poses more risk to the Company than hourly billable rates. On a per job basis, the Company states that the full cost of the job may not always be recovered. For example, if a job takes longer to complete than what is covered by the flat rate price, the Company may not recoup the full cost. However, the Company believes that in aggregate, flat rate pricing would recoup all costs. Beschler PFT, p. 19; Tr. 10/12/01, pp. 1796, 1800 and 1801; Tr. 11/5/01, p. 2918.

b. Hourly Billable Service Rates

Yankee is also requesting an increase to the billable service rates for those services not provided for under the flat rate pricing scheme. The proposed rates are based on 30-minute increments of service instead of the current 15-minute increments. The Company believes that this incremental breakdown would better reflect the actual amount of time these types of services usually entail as well as streamline record keeping. The Company also proposes to charge these rates on a per employee basis rather than the current incremental charges for an additional employee. Yankee states that nearly all appliance repairs jobs require only one employee. Beschler, pp. 20 and 21.

The proposed billable service hourly rates are as follows:

	Per Employee
Mon.-Fri. 8:00 a.m. to 4:30 p.m.	\$50.00 for the first 30 minutes or fraction thereof
	\$30.00 for each additional 30 minutes or fraction
Emergency work after regular hours, weekends, holidays	\$65.00 for the first 30 minutes or fraction thereof
	\$35.00 for each additional 30 minutes or fraction

Beschler PFT, p. 21.

Yankee states that its proposed billable service rates would fully recover the cost of these services from the customers who choose to use these services. This ensures that other customers would not subsidize these costs. Beschler PFT, p. 21; Tr. 11/5/01, pp. 2918 and 2919. Yankee also states that if flat rate pricing was not approved its proposed hourly billable rates and the proposed rate year revenue for

billable appliance services would not change. Tr. 10/12/01, pp. 1793-1794 and 1808.

c. Department Analysis

Pursuant to Conn. Gen. Stat. §§ 20-541, the Department is required to ensure that a public service company, as defined in Conn. Gen. Stat. § 16-1, fully recovers the cost of performing gas service work. Conn. Gen. Stat. §§ 20-540 defines gas service work as the '...repair, alteration or maintenance of equipment, appliances, accessories or fixtures within or adjacent to a building or structure in connection with the utilization of gas supplied by a public service company.'

Based on the evidence presented, the Department believes that charging a flat rate for appliance service work is not appropriate. Under this type of pricing structure, it is possible for a customer to be over-charged for a particular job that may not take as long as was anticipated in the Company's statistical analysis, or to be undercharged. In the event of the latter, the Company would not recover the full cost of providing the service. According to Yankee, the proposed hourly billable service rates will recover all the costs associated with each job. It is the Department's primary concern that the revenue from billable appliance services recovers the costs of providing such services. Therefore, the Department rejects the flat-rate pricing scheme for appliance service work. As billable appliance services are competitive in nature, the Department approves the Company's proposed increase in the hourly billable rates for all service work performed by the Company. Yankee testified that the billable appliance service rate year revenue would be the same whether the flat rate pricing proposal was approved. Tr. 10/12/01, p. 1808. Therefore, the Company's pro forma revenue adjustments for this service are appropriate. In addition, the Department approves Yankee's request that any future changes to billable appliance service rates be filed with the Department 10 days prior to the effective date.

3. Target Margin

[24] The purpose of interruptible service is to provide an outlet for a LDC's excess capacity that is not being utilized during off-peak periods. The generated revenue and margins are returned to ratepayers. Response to Interrogatory GA-103. The current interruptible target margin of \$5.52 million was established in the Decision dated August 26, 1992 in Docket No. 92-02- 19. The Company retains 100% of the first \$5.52 million of interruptible margin and any excess is equally shared between ratepayers and shareholders. The interruptible margin revenues help offset various costs incurred by Yankee that otherwise may have resulted in increased rates. The Department previously allocated 50% of the excess interruptible target

margin and off-system sales to fund transition costs associated with FERC Order 636. See, Decision dated July 8, 1994 in Docket No. 94-01-12, p. 10. More recently, the Department approved a settlement between Yankee and OCC, which allocated 80% of the excess target margin and off-system sales and 100% of capacity release credits to offset Yankee's deferred expenses. See, Decision dated January 3, 1996 in Docket No. 92-02-19RE02, Stipulation and Agreement, p. 3. Currently, firm customers receive 80% of the excess target margin while shareholders receive 20%. Soderman PFT, p. 12.

Given the volatility and risk associated with the competitive natural gas market, Yankee believes that the current target margin level of \$5.52 million is still appropriate. However, Yankee states it no longer has transition costs associated with FERC Order 636. It believes that the facts and circumstances that dictated the current margin **sharing** percentages have changed. Consequently, Yankee seeks to change the **sharing** percentage of the excess margin from 80/20 between **customers** and shareholders back to 50/50. There are currently different **sharing** splits for **capacity release** credits, off-system **sales** and interruptible margin. The Company believes that the **sharing** percentages should be consistent. It would provide the opportunity to use the three markets equally for the purposes of maximizing the potential value for excess pipeline **capacity**. The Company also believes that the 50/50 **sharing** provides an increased incentive to exceed the target margin while still providing benefits to the **customers**. Soderman PFT, pp. 12 and 13.

As indicated in the data below, Yankee exceeded its interruptible target margin of \$5.52 million for fiscal years 1992-2001.

Year	Margin (\$)
1992	8,550,589
1993	7,521,165
1994	7,013,758
1995	10,739,976
1996	8,683,644
1997	8,626,841
1998	5,615,917
1999	5,630,017
2000	9,096,214
2001	7,021,219

Response to Interrogatory GA-68RV01, p. 2.

OCC recommends that the Department's current policy should be maintained. OCC says that the evidence shows that the Company has historically exceeded the \$5.52 million interruptible margin and while the current policy adequately protects the Company

providing it with greater incentive to maximize net margins for the benefit of firm customers and shareholders. Further, the current policy recognizes that the interruptible target margins are difficult to forecast, and recognizes the volatility of oil and gas prices. OCC believes the existing policy recognizes the opportunity for financial windfalls and the underrecovery of distribution-related costs and recognizes that firm delivery customers pay for the large majority of distribution facilities and other costs. Ruback PFT, p. 10; Brief, p. 142.

The Department believes the evidence proves that the current policy for the interruptible target margin adequately serves its intended purpose in a fair and just manner to both firm customers and shareholders. The Department believes that the current policy provides the Company with enough incentive to maximize net margins for the benefit of both firm customers and shareholders. Historical data presented in this case shows that Yankee consistently exceeded its margin target, and in some years, by several million dollars. However, the Department notes that in two of the past four fiscal years Yankee barely achieved its target margin level. The Department is aware that this is due to the volatile nature of the competitive natural gas and the alternate fuels markets. As such, the Department understands that forecasting the interruptible margin is difficult. In addition, the Department believes that the current sharing percentages are fair because firm customers are funding the majority of the distribution facilities that service interruptible customers. Therefore, the Department believes that no change to the interruptible target margin level or its sharing percentages of excess margins are warranted at this time.

D. EXPENSES AND EXPENSE ADJUSTMENTS

1. Allocated Expenses from NU

[25, 26] In its Application, the Company included \$12,710 of charitable contributions and \$80,633 of advertising expenses. These expenses were billed from affiliates and funded by ratepayers in Yankee's test year expenses. Response to Interrogatory OCC-116.

OCC indicates that expenses allocated to Yankee included \$12,710 in charitable contributions and \$6,990 of the \$80,633 total advertising expenses for NU's Electrical Safety Campaign. Further, OCC indicates that the Department has traditionally disallowed expenses associated with charitable contributions, requiring such expenses to be charged below the line. Brief, pp. 72 and 73.

The Department agrees with OCC and reduces Yankee's allocated expenses by \$19,700

(\$12,710 plus \$6,990). The Department has historically disallowed charitable contributions. Further, the \$6,990 does not relate to the provision of gas service and should not be funded by Yankee's ratepayers.

2. American Gas Association Dues

[27] The Company indicated that \$7,000 or 3.57% of \$196,000 of test year American Gas Association (AGA) expense should be adjusted out of its rate request. This is based on the AGA audit report for the year ended December 31, 1998 issued by the National Association of Regulatory Utility Commissioners (NARUC). WP C-3.17.

OCC argues that 23.86% of the AGA expenditures pertain to AGA's government relations costs which includes the 3.79% of lobbying costs aforementioned. Schultz and DeRonne PFT, p. 50. The 23.86% was taken from the same NARUC report used by the Company and related to Government Relations Expenses in the AGA's Summary of Expenses. Tr. 10/18/01, pp. 2224 and 2225. Therefore, OCC requests that rate year above-the-line expenses should be reduced by an additional \$40,000. Schultz and DeRonne PFT, p. 50.

In a previous Decision, the Department adjusted 22.57% of AGA dues to below-the-line expenses. See, Decision dated January 28, 2000 in Docket No. 99-04-18PH02, DPUC Review of The Southern Connecticut Gas Company's Rates and Charges -- Phase II, p. 21. The Department accepts OCC percentage as being the more representative and reduces allowable AGA dues by \$39,337 [\$196,000 times (23.86% less 3.79%)] resulting in an allowed amount of \$149,663.

3. Corporate Headquarters

[28] In its Application, Yankee included the annual lease, operating and maintenance and moving costs associated with its Corporate Headquarters at 599 Research Parkway, Meriden, CT in rate year expenses. Response to Interrogatory GA-349; Tr. 10/12/01, p. 1851. These annual costs are \$810,000 for rent expense, \$260,000 for O&M expenses and \$100,000 for the cost associated with the move of the Corporate Headquarters from Meriden to Berlin for a total annual expense of \$1,170,000. The Company is expected to finalize the move to Berlin by the end of the first quarter of 2002. Therefore, Yankee contends that the rate year should include 3/12ths of the rent and O&M expenses plus the \$100,000 moving expense. Response to Interrogatory GA-349, pp. 1 and 2.

OCC recommends that the adjusted rate year expense be reduced by \$1,170,000 to reflect removal of all of the rental and maintenance expenses included in the rate year. Its argument is that rate year expenses include a full year of costs to be allocated from NU including building overhead charges. Further, OCC recommends that the one-time charge for moving expense be amortized over a five-year period. Brief, p. 70.

The Department finds that the Company should be recompensed for: 3/12ths of the annual rent (3/12 times \$810,000) or \$202,500; 3/12ths of annual O&M expenses (3/12 times \$260,000) or \$65,000; and the one-time \$100,000 for moving expenses in the rate year. However, this sum of \$367,500 (\$202,500 plus \$65,000 plus \$100,000) will be amortized over the four-year rate period to avoid over-compensating the Company for these non-recurring expenses. Therefore, the Department allows rate year expense of \$91,875 (\$367,500 divided by 4) and disallows rate year expense of \$1,078,125 (\$1,170,000 minus \$91,875).

4. Department Assessment

[29] In its Application, the Company requested a rate year expense of \$957,000 associated with its annual regulatory assessment by the Department. OCC notes that the Company's most recent invoices show Yankee's current actual assessment to be \$1,071,479, an amount \$114,479 higher than its requested rate year expense. Accordingly, OCC agreed with the Company that the pro forma level of assessment expense should be adjusted to reflect the most current data available. Brief, p. 73.

The Department agrees with OCC and increases the allowed assessment expense by \$114,479.

5. Depreciation Expense

a. Overview

[30-32] The Company's proposal for depreciation expense is based primarily on the results obtained by a depreciation study of its plant-in-service as of December 31, 1999. Schedule H-1.7. Those results plus adjustments applied to the Company's average depreciable plant-in-service during the rate year results in an overall depreciation rate of approximately 4.05% and a depreciation expense of \$27,316,000. The depreciation study was conducted using the remaining life technique (RL

technique) and equal life grouping (ELG). The RL technique is designed to recover the undepreciated portion, net of salvage, of each account over the expected composite remaining life of each given account. As such, the depreciation rate on an account is dependent on the expected average service life, age, expected net salvage value, and accumulated depreciation. This rate changes when these various components change. ELG is a procedure for grouping assets within an account so that assets of equal expected lives are grouped together. The undepreciated portion of the subgroups are recovered over shorter or longer periods.

The ELG procedure contrasts with another grouping procedure, average life group (ALG), that groups assets within accounts according to the average expected life of the assets. For example, if all the assets in an account are expected to have an average service life of 10 years (as with any average some of the assets will last more than 10 years, others less), the ALG procedure would group them all together and depreciate each asset over 10 years (a 10% rate assuming zero net salvage). By contrast, the ELG procedure would further subdivide the assets into groups of assets that span the range of lives that make up the average. Depending on where a subgroup falls in the range, the subgroup may be depreciated over 2 years, 20 years or somewhere in-between even though the subgroups are all from the same pool of assets that have the same expected 10 year average service life (ASL). While either procedure will fully recover the cost of an account over the full life of the account, they do so at differing rates during the course of that period.

In reviewing the Company's proposal for depreciation rates, the Department considered the appropriateness of the procedure used, as well as the ASLs and net salvage values. Except as detailed below, the Department finds the Company's conclusions and proposals with regard to depreciation rates appropriate. In aggregate, the Department's adjustments to the Company's proposed depreciation rates reduce the overall rate on depreciable plant from approximately 4.04% to approximately 3.16%. In addition to adjustments to the Company's proposed depreciation rates, the Department also made changes to its proposed plant-in-service. See, Section II.B. Rate Base. The combined impact of changes to the depreciation rates and plant-in-service have reduced the Company's proposed depreciation expense by \$6,069,659 from \$27,316,000 to \$21,246,491.

b. ELG Versus ALG

In proposing to continue with the ELG procedure, the Company asserts that this procedure provides a more systematic and equitable recovery of capital, better connecting the recovery of the cost of capital assets with the use and consumption of those assets. Schedule H 1.7, pp. 9 and 10. In support of the ELG procedure the Company has provided Engineering Research Institute Bulletin 155 which claims that,

based on certain criteria, the ELG procedure is the 'only mathematically correct method.' Late Filed Exhibit No. 105, Bulk, Bulletin 15, p. 6. OCC raised concerns about the Company's use of the ELG procedure, stating that Yankee is unique among Connecticut utilities in using the procedure. Further, the procedure may give the Company incentives to retire assets sooner and take on additional capital projects. Brief, p. 76.

The Department's assessment of the ELG procedure hinges on the ability of that procedure to accurately reflect the consumption of assets over time relative to the ALG procedure. In rejecting CNG's request in its last rate case to use the ELG procedure, the Department found that the ELG procedure did not do as good a job as the ALG procedure in matching loss in production value with depreciation expense. See, Decision dated May 25, 2000 in Docket No. 99-09-03PH01. The flaw in the ELG procedure is that it assigns equal cost recovery to assets in an account regardless of the expected life of those assets. Tr. 10/15/01, pp. 1993-1998. Since asset life is a proxy for useful production, short lived assets should be assigned lower cost recovery than longer lived assets. This is the result achieved under the ALG procedure as the assets in an account are assumed to be depreciated at the same rate. Thus, longer lived assets recover more costs than shorter lived assets, reflecting the greater production value of longer lived assets.

Consistent with its Decision in CNG's last rate case, the Department continues to believe that capital recovery should approximate the consumption of an account's production value. Since the ALG procedure better achieves this approximation relative to the ELG procedure, the Department will use the ALG procedure for setting depreciation rates for the Company. Use of the ALG procedure changes the RLs and depreciation rates for the following accounts as indicated.

Account No.	RLs	Depreciation Rate
305	from 17.3 to 19.5	2.26 to 2.01%
307	from 6.8 to 6.7	4.35 to 4.42%
311	from 12.0 to 12.8	2.63 to 2.45%
320	from 9.1 to 10.4	1.10 to 0.97%
363.4	from 11.7 to 13.4	3.51 to 3.06%
363.5	from 11.9 to 13.7	3.51 to 3.05%
375.1	from 25.2 to 32.4	3.07 to 2.39%
376.1	from 36.6 to 39.7	2.49 to 2.30%
378	from 18.9 to 22.2	3.42 to 2.91%
379.1	from 26.6 to 31.7	3.12 to 2.61%
386.1	from 26.0 to 30.6	4.30 to 3.66%
381.1	from 12.3 to 12.7	5.37 to 5.20%
382	from 29.0 to 35.0	2.38 to 1.97%
385.1	from 29.6 to 35.0	3.33 to 2.82%

387	from 19.1 to 19.4	3.82 to 3.76%
390	from 21.1 to 27.6	3.75 to 2.87%
397	from 13.5 to 14.5	5.21 to 4.85%

c. ASLs and Net Salvage Rates

With regard to the Company's proposed ASLs and net salvage rates, the Department makes the following adjustments. The proposed ASL on the Company's new customer connection information system is five years. The basis for this proposal is the Company's 'internally developed 5-year life' and not the result of detailed studies of the life characteristics of the account as is the case for most of the other accounts in the depreciation study. Schedule H-1.7, p. 27. Indeed, OCC points out that the Company failed to provide any technical or logical evidence in reducing the life for the account from 10 years to 5 years. Brief, p. 80. The Company's own experience and testimony indicates that 5 years is unreasonably short for this kind of equipment. Tr. 10/15/01, pp. 2007-2013 and 2054. Based on the Company's experience with its last customer information system, the Department will assign an ASL of 10 years to this account, Account 391.11. Use of a 10-year ASL increases the RL on the account from 4.5 to 9.5 years and decreases the depreciation rate from 20.0% to 9.47%.

The proposed net salvage rates on Accounts 380 and 397 of negative 80% and 0%, respectively, are low relative to the recent history on the accounts. Recent experience for Account 380 shows a negative net salvage experience of approximately 33%. While this experience is at odds with the Company's prior experience for the account, it recently changed the process for retiring assets in the account and intends to continue with it. Tr. 10/15/01, pp. 1989-1991. Based on the Company's recent experience and its intent to continue in a new process, the Department believes it appropriate to increase the net salvage rate on this account from negative 80% to negative 60%. The change to net salvage decreases the depreciation rate from 3.66% to 3.00%. Account 397 shows a recent retirement that produced net salvage of nearly 50%. While this may not be a typical result for this account, the sale of equipment at significant positive salvage cannot simply be dismissed as an outlier as done by the Company in its proposal on the account. Late Filed Exhibit No. 98. Rather, the result should be considered as part of the overall history of the account, where most retirements yield little if any net salvage, but from time to time significant salvage is realized. As such, the Department will increase the expected net salvage rate on this account from 0 to 10%. The change to net salvage decreases the depreciation rate from 4.85% to 4.16%.

6. Cost of Depreciation Study

OCC recommends that the cost of the Company's depreciation study be expensed over five years to correspond to the typical length of time between such studies. Brief, p. 79. The Department agrees that this is a relevant consideration. As such, and since the study was entirely expensed in the test year, the Department will increase the cost of the Company's depreciation study included in the rate year by \$4,746 (\$0 plus \$23,730/5).

7. Employee Benefits

a. FAS 106

[33, 34] Under the FAS 106 -- Employers' Accounting for Post-Retirements Benefits Other Than Pensions FAS 106, Yankee is required to recognize post-retirement benefits other than pensions during the working career of employees, not after they retire. Costs accrue from the date an employee is hired to the date an employee retires and is fully eligible to receive FAS 106 benefits. The present value of future benefits would be determined by employee retiree demographics.

Yankee adopted FAS 106 and is funding two voluntary employee benefit association (VEBA) trusts for post-retirement medical benefit expenses. One VEBA is for management employee benefits and the other is for union employee benefits. Investment earnings in the union VEBA is not subject to income taxes, while investment earnings in the management VEBA is subject to unrelated business income taxes. Response to Interrogatory GA-71. The Department approved the adoption of FAS 106 in Yankee's last rate case in the Decision dated August 26, 1992 in Docket No. 92-02-19. It allowed \$1,728,000 million in annual expense to fund the VEBA trusts. At that time, the \$1,728,000 was the maximum deductible contribution for tax purposes that Yankee could incur relative to the union VEBA. Mahoney PFT, p. 11.

In its original Application, Yankee proposed a rate year adjustment of \$2,742,000, for a total expense of \$4,470,000, which consists of three components. Schedule C-3.20. The first component is an increase of \$1,439,745 to the test year expense of \$1,728,000 which reflects the projected annual FAS 106 expense level of \$3,171,000 as calculated by Yankee's actuary, Watson Wyatt Worldwide. WP C-3.20h. Yankee revised this expense downward by \$171,000 to \$1,272,000 for the rate year adjustment due to the sale of R.M. Services (RMS), which resulted in their employees not being part of the plan. Response to Interrogatory OCC-16.

The second component of FAS 106 expense is the amortization of the regulatory asset that was created as a result of prior FAS 106 expenses that exceeded the allowed

annual level of \$1,728,000. This regulatory asset is projected to be \$3,474,000. Yankee proposed to amortize the \$3.5 million balance over four years, which results in an annual amortization expense of \$869,000. Work Paper C-3.20h. This regulatory asset projection was revised showing a deferred FAS 106 balance of \$2,821,515. Late Filed Exhibit No. 71. Using this balance, the annual amortization expense becomes \$706,000.

The final component of FAS 106 expense is the amortization of the regulatory asset created as a result of the NU/Yankee merger. Due to the merger, on March 1, 2000 the post-retirement obligation was changed to reflect the fair value of this obligation. On this date, Yankee recorded a deferred credit of \$4.0 million because the accumulated post-retirement benefit obligation exceeded the value of the plan assets. Yankee believes that the recognition of the \$4.0 million did not affect the net periodic benefit cost on March 1, 2000 because a corresponding regulatory asset was recorded at the same time. Yankee believes that the \$4.0 million regulatory asset should be amortized over an average period of 9.3 years, which results in annual amortization expense of \$430,000. Work Paper C-3.20h. Yankee asserts that absent the NU/Yankee merger the amortization would have been included in the actuary's determination of the net periodic benefit cost. Mahoney PFT, p. 12. Yankee revised the FAS 106 regulatory asset amortization to reflect the sale of RM Services (RMS) for a decrease of \$20,000 to the original rate year adjustment of \$430,000, producing a new rate year adjustment of \$410,000.

In total, Yankee's original overall adjustment to FAS 106 expense is an increase of \$2,742,000. This was added to the test year expense of \$1,728,000 and produces a rate year expense level of \$4,470,000. Mahoney PFT, pp. 11 and 12; Schedule C-3.20. Taking into account Yankee's various scenarios, the Department calculated a revised rate year adjustment of \$2,388,000, which produces a rate year expense of \$4,116,000.

Yankee originally proposed a \$3,171,000 (\$1,728,000 test year expense + \$1,443,000 rate year adjustment) FAS 106 expense based on the following assumptions.

	February 29, 2000	December 31, 2000
Discount Rate	7.50%	7.75%
Expected return on assets	9.00%	9.00%
Salary increases	4.00%	4.50%
Health care trend rate	5.00%	5.00%

Response to Interrogatory GA-72.

The discount rate, defined as the rate of interest under which the FAS 106 plan's obligations could be settled, is intended to reflect market interest rates at the time of valuation. Yankee's actuary testified that the standard for setting the discount rate is double A corporate bonds. Tr. 10/11/01, p. 1591. The Department believes that the 7.75% discount rate is reasonable because it reflects market interest rates at the time the actuary calculated the FAS 106 expense.

A long-term rate of return is used to calculate the expected investment income on the fair value of FAS 106 assets. These assets are determined at the beginning of the year and adjusted for benefit payments and contributions expected to be made during the year. Historical rates of return on FAS 106 plan assets are at --1.9% for 2000, 12.1% in 1999, 23.9% in 1998, 20.4% in 1997 and 13.9% in 1996. Response to Interrogatory GA-75. Yankee's actuary gave testimony that equity markets were down 20% to 30%, and fixed income securities are yielding 6.0% to 6.5%. Tr. 10/11/01, pp. 1596 and 1597. The Department concludes that returns on pension plan assets are not as great now as in past years due the depressed markets. The Department believes the long-term rate of return should be set at 9.0% for ratemaking purposes given the long-term nature of the assumption and the actuary's judgement. The salary increase assumption of 4.5% is an input to the life insurance portion of the FAS 106 expense and is an insignificant portion of the calculation. Tr. 10/11/01, pp. 1601 and 1602. The Department believes that the 4.5% salary increase is reasonable.

The health care trend rate is the level of expected increase in health care costs and was set by the actuary at 5.0%. The health care claims cost assumption is a long-term economic assumption. It is developed based on the prior year claims cost provided by Yankee increased by one year's trend, and expected claims cost based on historical information. The actuary reviews these numbers for reasonableness based on his knowledge of the costs for similar FAS 106 plans sponsored by other corporations. Tr. 10/11/01, pp. 1603 and 1604; Late Filed Exhibit No. 69. The Department believes 5.0% is reasonable.

OCC recommended a reduction in Yankee's requested expense level for FAS 106 by \$171,000 since RMS was sold and is no longer included in the FAS 106 expenses. Response to OCC Interrogatory Nos. 15 and 16; Schultz and DeRonne PFT, p. 42. The other parties and intervenors were silent on this issue. OCC, as well as other parties and intervenors, made no adjustment to FAS 106 expense based on the discount rate, long-term rate of return, salary increase, or medical trend rate.

The Department agrees with OCC that an adjustment should be made to recognize the sale of RMS, which was an affiliated non-regulated company. The employees of RMS were covered for FAS 106 benefits and included in the VEBA. Subsequent to the sale, these employees are no longer covered under Yankee's FAS 106 benefits. Therefore, an

adjustment has to be made to remove them from the FAS 106 expense. Yankee provided this adjustment, which results in a decrease of \$171,000. Response to Interrogatory OCC-16. The Department concurs with this adjustment and reduces the FAS 106 expense by \$171,000.

Yankee's original Application proposed the recognition of a \$1,003,000 regulatory asset due to the NU/Yankee merger with an amortization of 9.3 years. Due to the sale of RMS, the amortization of the FAS 106 regulatory asset must be changed. The following table shows the amortization of FAS 106 regulatory assets:

Unrecognized items as of	Amortization Balance	Years Remaining	Annual Amortization
February 29, 2000	(\$000's)		(\$000's)
Transition Obligation	\$11,491	13.12	\$876
(Gain)/Loss	(7,488)	16.78	(446)
Net Regulatory Asset	4,003		430
Less: R.M. Services	339	16.78	20
Regulatory Asset excluding R.M. Services	\$3,664		\$410

Response to Interrogatory OCC-15

OCC recommended a reduction to the FAS 106 regulatory asset amortization expense by \$20,000, due to the sale of RMS, citing calculations provided by Yankee in response to OCC Interrogatory No. 15. Schultz and DeRonne PFT, p. 42. The Department agrees that the FAS 106 regulatory asset should be reduced given the sale of RMS. The average remaining years calculation is calculated by dividing the net amortization balance of \$3,664,000 by the annual amortization of \$410,000 which is 8.94 (\$3,664,000/\$410,000) years. Based on the aforementioned, the Department decreases the FAS 106 regulatory asset amortization by \$20,000 (\$430,000-\$410,000) from Yankee's original request.

The regulatory asset established due to the NU/Yankee merger represents the accumulated post-retirement benefit obligation in excess of the fair value of the plan assets as of March 1, 2000. Response to Interrogatory GA-82. The accumulated post-retirement benefit obligation is defined as the actuarial present value of all benefits attributed to service rendered prior to the measurement date. It is measured using an assumption as to future compensation levels when the benefit formula is based on future compensation levels. Response to Interrogatory GA-81. If the merger had not occurred, the actuarial calculations to determine the net periodic benefit cost would have included the accumulated post-retirement benefit obligation in excess of the fair value of the plan assets. Specifically, the

amortization of the accumulated post-retirement benefit obligation in excess of the fair value of the plan assets would have been part of the actuaries' calculation of the annual net periodic benefit cost and then recorded by Yankee and reflected in retail rates. Response to Interrogatory GA-82.

However, because the NU/Yankee merger did occur, FAS 106 required Yankee to recognize the accumulated post-retirement benefit obligation in excess of the fair value of the plan assets on its balance sheet at the time of the merger and to amortize the regulatory asset over an actuarially determined time period. In addition, the going forward (i.e., post March 1, 2000) actuarial calculations of the net periodic benefit cost exclude the accumulated post-retirement benefit in excess of the fair value of the plan assets. Therefore, the amortization of the accumulated post-retirement benefit obligation in excess of the fair value of the plan assets plus the going forward net periodic benefit cost, as provided by the actuaries, equals an annual level of expense that is approximately the same level of expense that would have been recognized if the merger had not occurred. Response to Interrogatory GA-82.

The NU/Yankee merger was accounted for under the purchase method of accounting in accordance with Generally Accepted Accounting Principles (GAAP). Purchase accounting requires the elimination of any unrecognized amounts from the acquired employer's plan. Response to Interrogatory GA-83. This treatment is outlined in paragraph 88 of FAS 106. Response to Interrogatory GA-73. Yankee's actuary calculated a net liability of \$4,003,000 that was recognized on the balance sheet. The corresponding journal entry, under the uniform system of accounts, is a debit to Account 182.EN Regulatory Asset for \$4,003,000 and a credit to Account 253.90 Accrued Liability for \$4,003,000. Response to Interrogatory GA-83. In addition, Yankee recorded a journal entry to remove \$338,947 for the RMS portion of the FAS 106 expense as calculated by Yankee's actuary. The corresponding journal entry, under the uniform system of accounts, is a debit to Account 253.90 accrued liability for \$338,947 and a credit to Account 182.EN Regulatory Asset for \$338,947. Response to Interrogatory GA-83. Yankee revised the deferred FAS 106 balance as of December 31, 2001 to \$2,821,515 in recognition of additional transition credits. Late Filed Exhibit No. 71. Based on the revised FAS 106 balance of \$2,821,515, OCC believes that a new four-year amortization should be \$705,379. Brief, p. 41. The other parties and intervenors were silent on this issue.

The Department recognizes Yankee's revision to its deferred FAS 106 balance from the original estimated beginning of rate year amount of \$3,474,000 down to \$2,821,515. Late Filed Exhibit No. 71. Yankee's original Application requested a four-year amortization of \$3,474,000, which equates to \$869,000 annually. Using the new balance of \$2,821,515, the annual amortization is \$705,379 ($\$2,821,515 / 4$ years). This equates to a reduction in FAS 106 deferred expenses of \$163,621 [$(\$2,821,515 / 4)$].

minus \$869,000]. During cross-examination, Yankee's witness agreed to the appropriateness of this adjustment given the new deferred balance. Tr. 11/5/01, p. 3087. Therefore, the Department reduces Yankee's FAS 106 deferred expense downward by \$163,621.

b. Qualified Pension Plan

[35] Yankee offers qualified pension plans (Plans) to its employees in both union and non-union pension plans. Yankee adjusted the test year pension expense of (\$2,907,000) to account for the actuarially determined net periodic pension credit. This net periodic pension credit decreased by \$359,000 to a rate year level of \$2,584,000. In addition, as a result of the NU/Yankee merger, the pension obligation was adjusted to reflect the fair value of the obligation on March 1, 2000. This fair value of the pension plan assets exceeded the projected benefit obligation by \$39,300,000 and therefore resulted in the recognition of a deferred debit. The recognition of the \$39,000,000 did not impact the net periodic pension credit on March 1, 2000 because a corresponding regulatory liability was recorded to offset it. Based on an actuarial study, it was determined that the \$39,300,000 regulatory liability should be amortized over an average period of 15.82 years, resulting in an annual amortization expense of (\$2,500,000). Without the NU/Yankee merger, this amortization would have been included in the actuary's determination of the net periodic pension credit. Therefore, the overall adjustment to pension expense is (\$2,100,000) which equates to a rate year expense level of (\$5,048,000). Mahoney PFT, p. 13. This can be seen in the following:

Description	Test Year	Test Year	Test Year	Rate Year	Rate Year
	Actual (\$000)	Pro Forma Adjustments (\$000)	Pro Forma (\$000)	Adjustments (\$000)	12/31/02 (\$000)
Pension Accrual	9/30/00 (\$2,907)		(\$2,907)	\$359	(\$2,548)
5p					
Pension					
Regulatory					
Liability					
Amortization		\$ (1,458)	(\$1,458)	(\$1,042)	(\$2,500)
5p					
Total Pension	(\$2,907)	(\$1,458)	(\$4,365)	(\$683)	(\$5,048)
Expense					

Schedule WP C-3.20i

Although Yankee is not requesting a pension expense due to its negative expense

level, the Department analyzed the negative balance based on the actuarial assumptions of a 7.50% discount rate, a 4.50% salary increase, and a 9.0% long-term rate of return. Response to Interrogatory GA-87. The discount rate, defined as the rate of interest under which the Plan's obligations could be settled, is intended to reflect market interest rates at the time of valuation. Yankee's actuary testified that the standard for setting the discount rate is double A corporate bonds. Tr. 10/11/01, p. 1633. The Department believes that the 7.75% discount rate is reasonable because it reflects market interest rates at the time the actuary calculated the pension expense.

The long-term rate of return on plan assets is used to calculate the expected investment income on the fair value of Plan assets. These Plan assets are determined at the beginning of the year and adjusted for benefit payments and contributions expected to be made during the year. Funds from pension plans are usually invested in a diversified portfolio of United States (US) and non-US equities, US and non-US fixed income securities, real estate and various types of private equities. Returns on these types of investment vehicles are subject to variability due to the changeability of the securities markets. The return on the US and non-US equities have been negative over the past year; however, longer term returns have been positive. Response to Interrogatory GA-90. Actual historical returns on Yankee's Plans are 18.4% in 1996, 22.6% in 1997, 16.9% in 1998, 15.9% in 1999 and -4.67% in 2000. Response to Interrogatory GA-94. The Department believes a 9.00% return on plan assets is reasonable.

Salary growth is the anticipated growth rate in the aggregate salary level of the Plan's participants. Yankee's actuary testified that he took into consideration historical salary growth, expectations of future increases given positions in the past and positions anticipated for the future. Tr. 10/11/01, p. 1635. Historical rates of salary increases are 5.57% in 2000, 4.42% in 1999, 2.61% in 1998, 6.43% in 1997 and 5.60% in 1996. Based on the actuary's testimony and historical rate of salary increases the Department believes a 4.50% salary increase assumption is reasonable.

At the request of Yankee, the actuary updated the fiscal 2002 budget amount for pension expense. The Company produced a rate year pension accrual of \$1,732,000 and a revised regulatory liability amortization expense of (\$2,482,000). Late Filed Exhibit Nos. 69 and 73. The actuary used a -10% return on asset assumption, which the Department determines was the driving force effecting the pension expense to change so dramatically. The Department usually uses the most up to date information but believes in this particular instance this should not be the case due to circumstances brought to light during cross-examination. Yankee believes that the equity markets were severely depressed in the third quarter due to events on September 11, 2001. Tr. 10/11/01, p. 1600. However, this Yankee witness further

states that:

I think that you would look at the returns in the 1996 to 1999 time frame and say those were abnormally high. And if you look at the return for 2000 and 2001 and say these were abnormally low, and thus you get a normal return of about 10 percent for stocks and about 8 and a half to 9 percent for the whole portfolio.

Tr. 10/11/01, pp. 1600 and 1601.

OCC believes that the pension expense should be decreased by \$18,000 to remove amounts associated with RMS, which has been sold. Schultz and DeRonne PFT, p. 41. In their brief, OCC reiterated their position stating that the amortization of the regulatory pension liability included in the filing should be reduced by \$18,000 to reflect the sale of RMS which results in an increase by \$18,000 in pension expense. Brief, p. 47. The other parties and intervenors were silent on the issue. OCC, as well as other parties and intervenors, made no adjustment to the pension expense based on the discount rate, long-term rate of return, and salary increase.

The Department agrees with Yankee's witness that a normal return of about 10% for stocks and about 8.5% to 9% for the whole portfolio is more realistic than a -10% return. Therefore, the Department finds these updated actuarial pension costs should not be used. The Department believes that due to the sale of RMS, pension expense amounts associated with RMS should be omitted from Yankee's pension plan expense since its employees are no longer in the plan. Consequently, there is a revision to the negative pension expense of \$19,000. Response to Interrogatory OCC-50. OCC's \$18,000 reduction is different from the Department's due to rounding. Tr. 10/18/01, p. 2340. This is reflected as an increase to the negative pension expense of (\$2,548,000) by \$19,000, which equates to (\$2,529,000). Therefore, the Department adjusts Yankee's requested negative pension expense by \$19,000 to (\$2,529,000) [(\$2,548,000) + \$19,000].

c. Retirement Programs

i. Supplemental Employee Retirement Program

[36] Yankee offers a supplemental employee retirement plan (SERP) to provide certain executives with a supplemental retirement benefit in addition to the benefit provided under the non-union pension plan. The projected benefits to be provided

under the SERP and the estimated costs of providing those benefits are determined on an annual basis through an actuarial valuation process based on various actuarial assumptions. Response to Interrogatory OCC-181. Yankee provided the actuarial statement on the SERP. Late Filed Exhibit No. 74.

OCC believes that an adjustment to Yankee's pro forma SERP expense should be made to reflect the most recent forecast of the rate year expense level. Based on Late File Exhibit No. 74 and cross-examination, OCC recommends that the level of the SERP expense of \$225,000 included in the rate year be reduced by \$162,373 to \$62,627. Brief, p. 41. The other parties and intervenors were silent on this issue.

The SERP expense is allocated to other affiliates if the Yankee executive spends time on the business of that affiliate since it is included as a part of the benefit costs within the payroll benefit allocation. Therefore, any payroll dollars charged to affiliates other than Yankee would be allocated a portion of the SERP expense. Late Filed Exhibit No. 75; Tr. 11/5/01, p. 3006. After analyzing the actuarial assumptions behind the SERP, the Department finds them to be acceptable. Late Filed Exhibit No. 74. The Department finds the SERP expense to have declined to \$62,627 as of October 18, 2001 from a level of \$225,000 for 2001. Late Filed Exhibit No. 74; Tr. 11/5/01, p. 3004 and 3005. This is due to changes in employee levels in that former officers terminated from Yankee without SERP benefits. Tr. 11/5/01, p. 3005. Therefore, the Department finds the appropriate SERP expense to be \$62,627, which equates to an adjustment downward of \$162,373 (\$225,000-\$62,627).

ii. 401(k) Plan

[37] Under Section 401(k) of the Internal Revenue Code, employees can set aside money for retirement on a pre-tax basis through a plan sponsored by their employer. Yankee offers a 401(k) plan to all its employees. Due to the merger, Yankee employees became part of the Northeast Utilities Service Company (NUSCO) 401(k) plan. All employees are eligible to participate after their hire date except for Yankee bargaining unit employees who are eligible after completing one year of employment. Contributions by employees range from 1% to 16% of base wages, with a maximum pre-tax contribution amount of \$10,500 in 2001. The Company match becomes available after six months of employment except for Yankee bargaining unit employees which becomes available after completing one year of employment. The amount of the Company's match, for all but Yankee bargaining unit employees, is 100% of the first 3% of pre-tax contributions. For Yankee bargaining unit employees, the amount of the Company match is 50% of first 5% of contributions. Employee contributions are 100% vested at all times. Company contributions are 100% vested at all times for all employees except Yankee bargaining unit employees. The Company's contributions for its bargaining unit employee's vest at rate of 20% per year of employment to a

maximum of 100% vesting at five years. Response to Interrogatory GA-89.

Yankee calculated the 401(k) plan expense by multiplying the rate year payroll by the average match rate of 2.26%, producing an expense of \$679,000 and adding an administrative fee of \$4,000 for a total rate year 401(k) expense of \$683,000 $[(\$679,000 \times 2.26\%) + \$4,000]$. Mahoney WP C-3.20g. The average match rate was developed by dividing the adjusted test year 401 (k) plan expense of \$622,000 by test year payroll of \$27,477,000 which is 2.26% $(\$622,000/\$27,477,000)$. Response to Interrogatory GA-198.

OCC adjusted the 401(k) plan expense due to its adjustment of payroll. Schultz and DeRonne PFT, p. 41. The adjustment was based on applying the 2.26% average match rate to the adjusted rate year payroll figure of \$27,069,000, producing an expense of \$612,000 and adding an administrative fee of \$4,000 for a total rate year 401(k) plan expense of \$616,000 $[(\$622,000 \times 2.26\%) + \$4,000]$. Their adjustment of (\$67,000) comes from subtracting their 401(k) plan expense of \$616,000 from Yankee's 401(k) plan expense of \$683,000. OCC stated that its adjustment for the 401(k) plan expense was based solely on the adjustment decreasing Yankee's payroll expense and that the average match rate of 2.26% would not change. Tr. 10/18/01, pp. 2342 and 2343. OCC reiterated its position on the 401(k) plan adjustment, stating that an adjustment to payroll affects the 401(k) plan expense. Brief, p. 45. The other parties and intervenors were silent on this issue.

The Department finds the methodology used by OCC to adjust Yankee's 401(k) plan expense for changes in payroll expense appropriate. While the Department has made no adjustment to payroll in the instant proceeding as discussed in Section II.D.13. Payroll Expense., the Department will true-up for that portion of payroll expense association with the system expansion program in the initial IERM proceeding. Should that true-up result in adjustments to payroll expense, an adjustment will also be made to the 401(k) plan expense.

8. Environmental Remediation

a. Background

[38-40] The Company is proposing \$3,365,000 in rate year expenses for remediation, removal, or containment of coal tar deposits. Of this amount, \$445,000 is for amortization of the December 31, 2001 projected deferred asset balance of \$1,779,000 over a four-year period. The remaining \$2,920,000 represents projected rate year remediation expenses. WP C3.13, p. 1. Yankee does not foresee any insurance

settlements with insurers on any parcels of land in the future. Responses to Interrogatories OCC-58 and GA-118.

Yankee states that it owns several properties that require environmental remediation. The chief need on most of these sites is for coal tar residue buried on-site. Coal tar is the by-product of running steam over coal to produce a combustible gas. Tr. 10/05/01, pp. 1130 and 1131. Coal tar can contain volatile chemicals or heavy metals, and becomes a point source pollutant as it leaches into ground water. Point source pollution is pollution directly originating from a specific location. In the past, the Company remediated and rolled costs into a deferred account for the next rate case. In a previous Decision, the Department allowed the Company to collect prudent, deferred remediation expenses cumulative to the rate case in addition to \$325,000 in rate year expenses. See, Decision dated August 26, 1992 in Docket No. 92-02-19, pp. 25-28. There was also a cap of \$2,500,000 put on total expenditures (including rates and deferred). Additionally, the Company's allowed rate of return of 6% for the environmental deferred balance was set to be comparable to the short-term cost of debt. Between 1995 and 1997, Yankee settled environmental liabilities with insurers, and collected \$9,628,000, which was netted against deferred expenses. Response to Interrogatory OCC-145; WP C-3.13, p. 1.

Yankee believes it has the responsibility to aggressively remediate the sites. Mahoney PFT, p. 16; Tr. 10/05/01, pp. 1108 and 1109. Remediation efforts will concentrate on Yankee's 11 former manufactured gas plant sites. Tr. 10/05/01, p. 1108. Yankee uses an outside contractor to physically remediate, while in-house personnel supervise and monitor excavation and disposal. The remediation work goes out for competitive bid. Id., pp. 1110 and 1111. Efforts involve remediating coal tar impacted soil, and not the underlying groundwater. Because of the large costs processing groundwater, industry tends to use natural attenuation to treat groundwater. Natural attenuation means allowing contaminants in the soil or groundwater to degrade naturally without treatment. Yankee uses wells to monitor ground water long-term, until a steady state level of pollutants is reached. Id., pp. 1114-1123. To conserve costs, the Company assured the Department that it does not continue monitoring for suspected pollution once the pollutants in question are under control. Id., p. 1122.

At the time of Yankee's last rate case in 1992, the Company was still in an assessment phase of its work on this problem. Accordingly, the allowance for expense recovery that was approved in that case was \$325,000 per year, which represented a five-year amortization of deferred costs accrued prior to the rate year (\$1,125,000), plus expenditures anticipated in the rate year (\$500,000. The Department also previously set a cap of \$2.5 million per year on total expenditures. See, Decision dated August 26, 1992 in Docket No. 92- 02-19, pp. 25-28.

Since that time, the Company has progressed from assessment to active remediation. Expenditures have increased considerably relative to pre-1992 levels as evidenced in the following table.

Fiscal Year	Coal-Tar Remediation Expense
1993	\$1,627,340
1994	687,740
1995	2,767,129
1996	2,231,270
1997	1,539,392
1998	3,197,260
1999	81,905
2000	477,657

Response to Interrogatory OCC-396, p. 2.

OCC disagrees with Yankee's requested rate year expense of \$3,365,000. It argues that the Company should not include the \$2,920,000 in estimated expenses from the year 2002. Expenses in 2002 are not known or measurable and have yet to be incurred. OCC agrees with Yankee that the Company should base rates, in part, on the \$1,779,000 in deferred costs for the period ending December 31, 2001. In addition to the \$445,000 amortization on the projected deferred asset balance, OCC suggests that an annual on-going expense level of \$500,000 should be added, not the \$2,920,000 as the Company proposes. Yankee would then have an annual expense level of \$945,000 included in rates (\$445,000+\$500,000). OCC also maintains that there should be a cap of \$5,000,000 put on total expenditures. If the Company's annual expenditures are less than \$500,000, then Yankee should record a negative deferral for the difference. That is, Yankee should not continue to collect money for spending less than it was given. OCC believes that Yankee is pursuing additional insurance recoveries, but the Company gave no indication of what the estimates were. Schultz and DeRonne PFT, p. 52-56; Tr. 10/8/01, pp. 2227-2229.

b. Department Analysis

In the past, the Department recognized that to the extent that coal-tar remediation expenses are prudently incurred, they should be allowed as proper operating expenses. See, Decision dated August 26, 1992 in Docket No. 92- 02-19, pp. 27 and 28. The expenses should be recovered through an allowance in the revenue requirement that is the basis for Yankee's rates. However, the Department cannot make an a priori ruling on the prudence of costs to be incurred. Consequently, the

Department's practice has been to provide for the recovery of expenses incurred since the prior rate case. However, costs incurred between rate cases are deferred until those costs can be reviewed for prudence in the succeeding case. The Department does not want the Company to profit from this activity and, therefore, required that deferred amounts accrue carrying costs at a rate that approximates the Company's short-term cost of debt. *Id.*, pp. 18 and 19.

The Department believes that proceeds from insurance settlements provided funding for remediation activities through fiscal year 2000. Therefore, the balance in the deferred account was actually a credit of \$840,480 at the end of the test year. Response to Interrogatory OCC-396. Expenditures of \$2,619,000 since that time are expected to result in a deferred balance of \$1,779,000 at the beginning of the rate year (January 1, 2002). Yankee expects to spend \$2,920,000 on this activity during the rate year. That amount, plus a proposed four-year amortization of the balance expected to be outstanding on December 31, 2001, is the basis for the Company's request to increase the allowance in its rate year revenue requirement to \$3,365,000. WP C-3.13.

The Department continues to believe that an after-the-fact review is the appropriate mode of consideration for these expenditures, rather than a priori approval. In this context, the Department notes that the 1994 management audit, conducted pursuant to Connecticut's periodic-audit statute [Conn. Gen. Stat. Section 16-8(b)], affirmed the Company's priorities for and its approach to its coal tar remediation program. Management Audit of Yankee Gas Services Company, prepared for the Department by The Liberty Consulting Group, January 27, 1995 (referred to hereinafter as the Management Audit Report).

The Department encourages Yankee's interest in environmental stewardship. Timely remediation is in the public interest, because it is important for utilities to clean sites as soon as possible to eliminate the possible human effects of hazardous waste and to avoid escalating costs. The Department agrees with the Company's general methodology of physically remediating sites. After remediation, monitoring wells are critical tools for measuring long-term progress in groundwater treatment. The Department agrees with the Company that monitoring wells must be funded until a steady state level of pollutants is reached. For example, though soil in Willimantic was excavated and backfilled, high levels of naphthalene remain in the groundwater. Response to Interrogatory GA-18. The Department takes keen interest in the effectiveness of Yankee's remediation efforts. Yankee volunteered to submit a report on Willimantic's progress and remediation effort. Tr. 10/05/01, p. 1124. In addition, the Company will be directed to address the necessity of funding long-term monitoring of groundwater on its sites.

The Department also observes that federal and state environmental authorities must be satisfied with Yankee's progress. The last correspondence from either agency on this subject was dated August 19, 1998. Response to Interrogatory GA-316, bulk attachment. On the basis of these observations, the Department finds that Yankee's expenditures on coal tar remediation since its last rate case are prudent.

The Department expects that Yankee's deferred account balance at the end of 2001 will be no greater than \$1,779,000. The Company's anticipated expenditures during the rate year are \$2,920,000. WP C-3.13. The Department believes that it is appropriate to use the same approach it used in Yankee's last rate case (see, Decision 92-02-19) with one exception. The Department elects to eliminate the current \$2,500,000 cap and replace it with a review of the Company's projects during the next rate case. Yankee's recoverable balance for the next time period is the sum of the deferred account balance and anticipated rate year expenditures, or \$4,699,000. Again using a five-year amortization period, the appropriate allowance for Yankee's rate year revenue requirement is \$939,800. In line with the prior Decision, the Department will allow carrying charges on the deferred balance equal to the rate on short-term debt.. See, Decision dated August 26, 1992 in Docket No. 92-02-19, p. 15. The Department sets the allowed rate on short-term debt at 4.72% in Section II.G. below. Based on the aforementioned, this results in a decrease of \$2,425,200 in rate year expenses for remediation, removal, or containment of coal tar deposits (\$3,365,000 less \$939,800).

c. Future Expectations

The Department's review of the Management Audit Report found that the auditors believed that Yankee's active involvement in the remediation program was an important factor in keeping down the costs of that program. Management Audit Report, pp. IX-4. The Department appreciates that observation. The Department will require that all reports related to environmental activity, such as the annual report and its presentations in rate cases, specifically address the Company's efforts to contain its costs. The Department believes that state and Federal environmental authorities will insist on the efficacy of the Company's remediation efforts. The Department has no intention of compromising the quality of those efforts. Its role in this matter is to approve the recovery by Yankee of the costs that it prudently incurs. The Department's specific interest is that Yankee's lack of profit from this activity not result in reduced management attention to it.

Another recommendation from the Management Audit Report was that Yankee explore the possibility of tax-exempt financing for its coal tar remediation efforts. The auditor estimated that use of tax-exempt financing, such as pollution-control bonds, could lower the cost of that financing by 250 basis points. Management Audit Report,

p. IX-14. The Company reported that it had not yet pursued that recommendation, as the proceeds that it received from its insurance carriers had forestalled the need for additional financing. Responses to Interrogatory GA-313.

The Department believes that since remediation expenditures now require financing, Yankee should pursue the auditor's recommendation. The Department will require that the Company provide a special report on the possibilities for tax-exempt financing. Use of tax-exempt financing would allow the rest of Connecticut to share Yankee's ratepayers' burden in paying for what amounts to an improvement in the quality of life for all citizens in affected communities.

Finally, the Department observes that the site that has recently been selected for construction of the Company's proposed LNG production and storage facility is also one of its coal-tar contamination sites. The Department will require that any coal-tar remediation expenditures necessary to prepare the site for the LNG facility be accounted for and financed separately from the other costs associated with the LNG facility. Remediation expenditures are to be accounted for and financed pursuant to the terms of this section, i.e., deferred with carrying costs accruing at a debt-only rate.

9. Inflation Adjustment

[41] The Department typically allows utilities to apply a general inflation factor to operation and maintenance (O&M) expenses not specifically adjusted for elsewhere. Yankee's filing used a proposed inflation rate based on the gross domestic product (GDP) price deflator published by Data Resources, Inc. in its Review of the U.S. Economy, May 2000. This source states that the GDP price deflator for both 2001 and 2002 is 1.8%. Yankee applied this 1.8% inflation rate to \$6,808,000 of residual O&M expenses producing a pro forma adjustment of \$324,000. Mahoney PFT, p. 20. This calculation was in error since the rates used were 2.2% for the test year and 2.5% for the rate year. Exhibit WP C-3.20. Yankee intended to use the value of 1.8% for both periods. The consumer price index-unadjusted (CPI-U) deflators were inadvertently used to represent escalation in the GDP deflator. Response to Interrogatory GA-62.

In addition, Yankee included in the residual O&M expenses a contractual expense with RMS. Response to Interrogatory GA-61. RMS is a corporation engaged in collection services. Yankee agreed on a five-year contract at a cost of \$173,000 per month or \$2,076,000 annually with RMS. Response to Interrogatory GA-60. By definition, residual O&M expenses should not include contractual expenses if they are known and measurable. As such the Department determines this contractual expense

with RMS should be excluded from the residual O&M expenses. Yankee recalculated residual O&M expenses for the test year at \$4,732,000 (\$6,808,000-\$2,076,000) and rate year at \$4,817,000 (\$6,893,000-\$2,076,000). Response to Interrogatory GA-60. Yankee revised its inflation adjustment to \$172,000 (\$85,000 + \$87,000), which includes the escalation factor change and the removal of the RMS contract. Response to Interrogatory GA-60.

OCC claims that Yankee's inflation adjustment should be decreased by \$152,000. Schultz and DeRonne PFT, p. 42; Schedule C-3. This reduction is based on subtracting the expense of the RMS contract from residual expenses. OCC bases this adjustment on the fact that Yankee recently entered into a five-year contract with RMS is known and measurable. As such, the costs associated with the RMS contract totaling \$2,076,000 should not have been inflated. A second correction was made to replace the incorrect escalation rates with the escalation rate of 1.8%. Schultz and DeRonne PFT, p. 42. OCC states that while the 1.8% escalation rate is lower than the more recent GDP price deflator, it is consistent with Yankee's budget assumptions and projections. Brief, p. 60. The other parties and intervenors were silent on the issue of inflation.

Yankee used the GDP deflator because the residual O&M expenses are not easily represented by a specific index. The GDP deflator represents the broadest measure of price inflation across the whole economy. Response to Interrogatory GA-63. The Department believes that the GDP deflator is a good proxy to use when escalating nonhomogeneous residual O&M expenses since it is a broad measure and best reflects these types of expenses. The Department used the GDP deflator for this type of adjustment in other Decisions. See, Decision dated January 28, 2000 in Docket No. 99-04-18PH02, Phase II; Decision dated May 25, 2000 in Docket No. 99-09-03PH01, Phase I.

Yankee updated its inflation adjustment from its original filing, using GDP deflators of 2.4% for the test year and 2.5% for the rate year. Response to Interrogatories GA-60 and GA-62. Yankee believes that the updated rates better reflect what the economy may experience and the price increases to which their residual O&M expenses may be subject.

The Department analyzed Yankee's inflation adjustment by considering the residual O&M accounts went into the inflation adjustment and the inflation rate used. Yankee states that the residual O&M accounts do not include nonrecurring items. Response to Interrogatory GA-61. Yankee applied factor substitution to mitigate the effects of inflation. Response to Interrogatory GA-59; Tr. 10/5/01, pp. 989-992. The Department analyzed the individual accounts, under the uniform system of accounts, that make up the residual O&M accounts and how they were adjusted. Response to Interrogatory

GA-64; Tr. 10/5/01, pp. 993-1000; Late Filed Exhibit No. 43. The Department finds that these residual O&M expenses should be included in Yankee's inflation adjustment with certain exceptions. The Department believes the RMS contract should be removed from residual expenses since it is a known and measurable expense. Therefore, the Department adjusts Yankee's original residual expense balance by subtracting the contract for RMS of \$2,076,000. In addition, Yankee also included the expense of its SERP in residual expenses.

The SERP is an extra retirement benefit to a select group of executives that provides for a supplemental retirement benefit above Yankee's regular pension plan. The Department reduces the residual expenses due to an adjustment by Yankee to its SERP expense. This is due to the decrease of \$141,000 from the test year amount of \$204,000 to the current level of \$63,000. This decrease is due to certain executives leaving Yankee before obtaining their SERP benefit. Response to Interrogatory OCC-181; Late Filed Exhibit No. 74. The SERP expense of \$63,000 is recorded above the line to Account 926.50. Therefore, the Department reduces the SERP expense of \$141,000 from the base of residual O&M expenses.

In addition, the Department rejects Yankee's updated inflation rate as shown by the GDP deflators of 2.4% for the test year and 2.5% for the rate year. Response to Interrogatories GA-60 and GA-62. The Department believes that inflation rates are continuously changing and that a higher rate at any given time may not represent the rate of inflation during the pro forma rate year. Tr. 10/5/01, p. 1001. In addition, due to the cooling economy, rates of inflation may be less in the future. Tr. 10/5/01, pp. 1001-1004. OCC's witness when questioned on the inflation rate stated, '[i]n looking on site, we requested their 2002, the most recent budget instruction for the budgeting process. That included various inflation rates, and some of those were around the 1.8% range. Some were higher. I don't think the 1.8% percent was unreasonable.' Tr. 10/18/01, p. 2346. The Department finds a 1.8% inflation rate to be reasonable.

Based on information in the record, the Department makes the following adjustments to Yankee's requested inflation adjustment:

Test Year Expense	
Total Year O&M	\$215,803,000
Known Adjustments	\$208,995,000
Test Year Residual	\$6,808,000
Test Year Pro Forma Expenses	
Test Year Residual	\$6,808,000
Less: R.M. Services	\$2,076,000

Less: SERP Expense	\$141,000
Net Test Year Residual	\$4,591,000
Pro Forma Escalation Rate	0.0180
Pro Forma Adjustment	\$83,000
Test year Pro Forma Residual	\$6,750,000
Rate Year Expenses	
Test Year Pro Forma Residual	\$6,750,000
Less: R.M. Services	\$2,076,000
Net Test Year Pro Forma Residual	\$4,674,000
Rate Year Escalation Rate	0.0180
Rate Year Adjustment	\$84,000
Rate Year Residual	\$6,834,000

Response to Interrogatory GA-60;

Response to Interrogatory OCC-181;

Late Filed Exhibit No. 74; WP C-3.21.

Applying these changes produces an inflation expense for Yankee of \$167,000 (\$83,000 + 84,000) which is a reduction in Yankee's request of \$157,000 (\$324,000-\$167,000).

10. Fuel Diversity Fund

[42] The Company proposes creation of a Fuel Diversity Fund (Fund) from which the proceeds are intended to encourage customers to utilize more efficient appliances than those often used with other energy sources. The Fund would be created by charging all firm customers, excluding special contracts, a \$.0091 per ccf surcharge on their bills, resulting in annual collection of approximately \$3,200,000 on a pilot basis. Morris PFT, pp. 9 and 10; Late Filed Exhibit No. 36, p. 2. Yankee proposes to offer an average of:

1. \$800 to residential customers to convert their heating systems to natural gas;

2. \$1,400 to commercial customers to convert equipment that uses at least 590 Mcf annually; and

3. \$10,000 to industrial customers to convert equipment that uses at least 4,200 Mcf annually.

Late Filed Exhibit No. 36, p. 2.

Yankee indicates that the proposed Fund is not intended for existing gas appliances because the benefits of switching from alternative fuels to natural gas exceed the benefits of gas-to-gas replacements. Further, the Company contends that the State's energy policy would be enhanced by enabling LDCs to provide customers with incentives to utilize more efficient appliances than those used with other energy sources. Therefore, while gas-to-gas switching might produce some efficiency gains, the full range of potential benefits can only be obtained through switching to natural gas from other fuels. Response to Interrogatory GA-249.

OCC and AG indicate that the proposed Fund promotes fuel switching in contravention of Conn. Gen. Stat. § 16-19d and should be denied. Further, OCC and AG cited that the Department, in recent rate cases, twice denied other LDCs' requests to charge ratepayers for the expense of similar proposed funds. OCC Brief, pp. 57-59; AG Brief, pp. 8-10.

CIEC agrees with OCC and AG that Yankee's proposed Fuel Diversity Fund surcharge contravenes Connecticut law and must be rejected. Further, the CIEC indicated that using a volumetric charge disproportionately charges industrial customers, who will see only 25% of distributed Fund collections. CIEC recommends that if Yankee desires such a Fund, then costs should be borne by Company shareholders. Brief, pp. 6-8.

The Department notes that Conn. Gen. Stat. § 16-19d(b)(4) permits the promotion or marketing of efficient gas and electric equipment which it determines: (A) is consistent with the state's energy policy; (B) is consistent with integrated resource planning principles; (C) provides net economic benefit to a gas public service company's customers and (D) does not have the primary purpose of promoting one fuel over another. In a previous Decision relative to Yankee's proposed gas incentive program, the Department indicated it 'has a continuing concern, which has been expressed in this and prior proceedings, about the use of ratepayer funds to place one form of energy in direct competition with another. It is also not completely convinced that incentive programs are the most effective method of

increasing the use of energy efficient appliances and equipment.'See, Decision dated January 11, 1986 in Docket No. 85-10-22, Application of The Connecticut Light and Power Company to Increase Its Rates and Revenues, p. 58.

In the Decision dated November 22, 2000 in Docket No. 99-04-18PH03, the Department rejected Southern's proposed marketing program that would have permitted contributions toward up-front equipment or installation costs up to \$600 per customer. Decision, pp. 10 and 11. Similarly in Docket No. 99-09- 03PH02, the Department rejected CNG's \$700 per customer marketing incentive plan. See, Decision dated May 9, 2001, p. 10. In both instances, the Department found that under Conn. Gen. Stat. § 16-19d ratepayers are not permitted to bear marketing incentive costs that fund a marketing effort designed to encourage fuel switching.

In the instant proceeding, the Department finds that the Company's proposed Fund encourages fuel switching and, therefore, contravenes Conn. Gen. Stat. § 16-19d and Conn. Agencies Regs. §16-19d-1 et seq. The Department directs the Company to book these types of marketing costs below the line and not include any Fund-related costs in O&M expenses included in rates. Therefore, the Department reduces O&M expenses by \$3,183,000.

11. Merger Synergies

a. Company Proposal

[43] Yankee has adjusted the ESM by removing 50% of the rate year base synergies, due to the merger with NU, from the calculation of revenue requirements. The remaining 50% of synergies remain as a reduction to revenue requirements. Yankee asserts that if 100% of the rate year synergies were reflected in rates, ratepayers would be receiving all of the synergy benefits and shareholders would be deprived of their opportunity to retain any of the merger synergies. Yankee believes that the mechanics of the calculation will work such that the synergies removed from the rate year, which are attributed to shareholders, will be excluded from earnings used to calculate the ESM. Yankee reasons that since rates have already been lowered by the ratepayer portion of rate year synergies, no adjustment for this portion is warranted. Yankee's methodology excludes the shareholder portion of base synergies from the ESM calculation to ensure the earnings used for the ESM do not recapture the shareholder portion and re-split these earnings 50/50. This mechanism will assure that shareholders receive their 50% share of synergies. Any incremental synergies achieved above the estimated rate year base amount will flow through the calculation of the ESM and be shared equally by customers and shareholders. Soderman PFT, p. 6.

In its original Application, Yankee's calculation of both administrative and general (A&G) and non-A&G synergies that will occur during the rate year is estimated to be \$7.0 million. The test year already reflects \$1.8 million of synergies with another additional \$5.2 million expected to be incurred by the end of the rate year. Mahoney PFT, p. 14; Schedule C-3.4. Yankee updated its merger synergy adjustment based on information accumulated in the discovery process. The main difference in the revision is that no savings are expected from sales and marketing in the rate year, which originally amounted to \$207,000. Late Filed Exhibit No. 14.

Yankee's identification of merger synergies began in August 1999, when a merger transition team that was comprised of representatives from both NU and Yankee was formed to assess the operating and administrative functions of both companies. The purpose of that review was to: identify and extract as much synergy savings as possible from the combined company; ensure that the going forward costs are reduced for both the combined company and for Yankee; propose a new organization; utilize best practice approaches whenever possible; achieve synergy savings as fast as reasonably possible; and identify and assign responsibility for integration projects. Eleven functional transition teams were created that had the general responsibility of identifying opportunities to increase efficiencies, eliminate duplication and provide improved customer service. These teams were as follows: operations; information technology/information systems (IT); finance, accounting, budgeting, treasury, investor relations and internal audit; sales and marketing; fleet and facilities; human resources; unregulated subsidiaries; legal, environmental, safety and insurance; regulatory affairs; governmental affairs; and corporate communications. Senior Management approved the recommendations of these functional teams in January 2000. Canyock PFT, p. 2. Examples of the teams' recommendations are as follows:

a. The operations team recommended the combining of both companies' call centers by 2002 to improve customer service and combining the procurement functions to attain volume discounts and negotiated savings.

b. The IT team recommended the migration of Yankee's outsourced mainframe data processing and storage environment to existing NU facilities and the combination of data networks.

c. The accounting/finance team recommended that all of the accounting and finance-related functions be combined at NU utilizing existing resources, with the exception of a small planning and reporting group that would remain at Yankee. This team also recommended that Yankee adopt the same enterprise computer applications as

NU for accounting and budgeting known as management information and budgeting system (MIBS), purchasing, stores and accounts payable (MIMS), and human resources and payroll (NUCHRIS).

d. The fleet and facilities team recommended the combination of existing transportation departments and the consolidation of facilities.

e. The human resources team recommended that Yankee move to the NU benefit plan.

f. The legal team recommended that work being performed by outside law firms at Yankee could be absorbed by existing internal resources at NU.

g. The regulatory affairs and governmental affairs teams recommended combining the environmental, safety and insurance functions at NU.

h. The corporate communications team recommended that additional savings could be realized through the elimination of Yankee's annual meeting and report to shareholders.

Many of the above recommendations resulted in functions being combined at NU. However, Yankee maintained dedicated support staff for several functions including: IT applications development and support, human resources, corporate communications and planning and budgeting. Canyock PFT, pp. 3 and 4.

In January 2000, as a result of the transition team's work, the estimated total combined synergies for NU and Yankee were the following:

Year	\$ Millions
2000	5.1
2001	11.7
2002	14.2
2003	15.2
2004	15.5

Once the transition team's recommendations were approved, an implementation project team was put in place and a detailed action item list was created to track each of the recommendations of the transition teams. At the end of 2000, all of the synergy

goals for 2000 were completed and the transition teams' synergy estimates were achieved. In addition, at the end of 2000, goals had already been achieved that would produce 93% of the 2001 projected synergies. Canyock PFT, pp. 4 and 5.

Yankee developed the rate year merger synergies through a pro forma adjustment to reflect the rate year level of merger synergies. Schedule C-3.4. The majority of the synergies result from combining the A&G functions at NU and Yankee and as such the A&G accounts were used as the basis for the merger synergy adjustment. The merger synergies that are reflected in the Schedule C-3.4 represent the difference between the A&G costs budgeted for the rate year and the actual test year amounts. The total test year amount for the A&G accounts (920 through 935) was obtained from Yankee's books and records. Because separate pro forma adjustments are proposed for employee benefits (account 926), worker's compensation and injuries and damages (account 925) and regulatory assessments (account 928), these amounts are excluded from the test year amount for purposes of calculating the merger synergy adjustment. Pro forma adjustments to the test year were also made to remove one-time merger related costs associated with the termination of Yankee's contract with IBM for outsourced mainframe data processing and storage, and to reflect escalation for payroll and non-payroll test year amounts.

The A&G charges budgeted for the rate year were also adjusted to exclude employee benefits, worker's compensation and regulatory assessments to be consistent with the test year. The adjusted rate year amount was then compared to the pro forma test year amount to derive the adjustment to reflect the rate year level of A&G synergies. In addition to A&G synergies, the transition teams identified synergies in operations and sales and marketing. The amount of the projected synergies in the rate year for these non-A&G areas has not been derived from the O&M accounts, but are reflected as additional rate year synergies in Schedule C-3.4 based on the amounts estimated by the teams. Yankee's share of the rate year synergies is projected to be approximately \$7.0 million, which is about half of the total projected synergies for the NU system for 2002. Canyock PFT, pp. 5-7.

Yankee adjusted the test year to reflect the rate year level of synergies. The adjustment to reflect the rate year A&G synergies is \$3.8 million, and the adjustment to reflect the rate year non-A&G synergies is \$1.4 million, for a total of \$5.2 million. Canyock PFT, p. 5; Schedule C-3.4. In addition to these adjustments, there are synergies already reflected in the test year A&G accounts. The NU/Yankee merger was consummated in March of 2000, therefore the test year reflects seven months of synergies. These synergies were identified by comparing the A&G accounts for the test year to Yankee's pre-merger budget for these same accounts, after adjusting the test year actuals for certain non-recurring payments. The synergies that were identified in the test year were calculated to be \$1.8 million. WP C-3.4, p. 2. The test year synergies of \$1.8 million and the adjustments

for the rate year level of synergies of \$5.2 million result in a total rate year level of synergies of \$7.0 million. Canyock PFT, p. 7.

The total synergies for 2002 presented in the merger case in Docket No. 99- 08-02 were \$10 million. The total synergies in the rate year for NU and Yankee combined that were identified by the transition teams subsequent to that docket were approximately \$14 million, or \$4 million higher than estimated in the merger case. The majority of these synergies result from combining A&G functions at NU and Yankee. Yankee's share of these synergies results from comparing the allocation to Yankee of the cost of the combined A&G functions as compared to what these functions cost Yankee on a stand-alone basis prior to the merger. For example, as a result of the merger, Yankee's annual meeting and report to shareholders were eliminated. After the merger, Yankee is allocated a share of the cost of NU's annual meeting and shareholders' report. The allocation to Yankee is less than what it paid prior to the merger, resulting in savings to Yankee. The allocation to Yankee of the cost of NU's annual meeting and shareholders' report, which is substantially unchanged as a result of the merger, also results in savings to the rest of the NU system. The combined savings to NU and Yankee are the total synergies that resulted from the merger. Yankee will realize about 70% of the total synergies estimated in the merger case, or about 50% of the higher total synergies that were ultimately identified by the transition teams. Canyock PFT, pp. 8 and 9.

The budgeting process and allocation of merger synergies are major factors in Yankee's merger synergy adjustment. The budget for NU, and now Yankee, is prepared on a business group basis. Each business group develops an annual budget in the fall of a given year for the following one to five years. For costs that affect Yankee, the relevant business groups consist of Yankee operations, Yankee customer service and NU corporate center. Yankee and NU corporate center developed detailed budgets for 2001 and 2002 in August to September of 2000. The basis for the budget is a five-year business plan, which is prepared by each operating company in the spring/summer and reviewed by senior management. The business plan sets the strategic direction for the companies and establishes financial and operational targets. For the NU corporate center functions, the basis for the budget are service level agreements (SLAs) that document the level and cost of services to be provided to the various companies and business segments that use these services. Canyock PFT, pp. 9 and 10.

SLAs are prepared each year as part of the budget process. Each of the functions within NU corporate center (e.g., accounting, insurance, communications, information technology, legal, purchasing) prepares a SLA for each of the major businesses (Yankee, electric utility group, and unregulated). This process begins with planning SLAs that identify the cost of the services to be provided by each function and how these costs will be charged to the operating companies or business segments for the

budget year. The business customers review the planning SLAs, and meetings are held between the customers and the service providers to discuss service levels and costs. The final documents are signed by representatives of the business groups and the service providers. SLAs were prepared for Yankee for the 2001 budget. In addition to costs, the SLAs describe the products and services to be provided by each function, strategic considerations, cost drivers and opportunities for cost reductions, and measures. Canyock PFT, p. 10.

The cost control center (CCC) managers are responsible for developing and inputting their O&M and capital budgets into MIBS. Individual CCCs are grouped into organizational and reporting hierarchies that roll up to the various business groups. Within each CCC the costs of the required resources (e.g., labor, materials and supplies) are budgeted sufficient to accomplish the various activities to be performed by each CCC. Canyock PFT, p. 11.

The merger affected Yankee's budget process almost immediately. Yankee was included in the NU process to develop the 2001 and 2002 budget. Yankee input its budget into the MIBS for the first time in September of 2000. Both Yankee and NU reflected the recommendations of the transition teams in developing their budgets. The corporate center was responsible for and charged for the transfer of personnel between Yankee and NU and the additional costs to provide services to Yankee for those functions that were being combined at NU. The allocation rates were also adjusted to include allocations to Yankee where appropriate. Canyock PFT, p. 11.

There is an allocation of corporate center functions whereby NU corporate center functions direct charge their costs to specific operating companies or business segments whenever possible. Costs that are not directly charged are allocated based on predetermined rates that are in place for each CCC. Each CCC has a functional profile that documents these rates. The allocation rates and formulas are filed annually with the Securities and Exchange Commission (SEC). Many of the rates are based on payroll or number of employees. As part of the annual budget process, a review of each CCC's functional profile is undertaken. In the case of Yankee, existing CCC functional profiles had to be modified to reflect the fact that Yankee would be allocated certain NU corporate center costs as a result of the merger and the recommendations of the transition teams. NU's accounting department worked with each of the CCCs to determine how Yankee should be included in these profiles for the 2001 and 2002 budgets. Canyock PFT, pp. 11 and 12.

Once the budget figures have been input into the MIBS, the budget is verified and reviewed for system input errors, completeness, budgeted costs versus targets, and other reasonableness checks. Once this process is complete, senior management reviews the budget. The final budget is then presented to the NU Board of Trustees

in December of each year. Canyock PFT, p. 11.

b. Party and Intervenor Positions

OCC provided analysis in its pre filed testimony on this adjustment for merger synergy savings. Its analysis shows that Yankee's filing comprises two separate adjustments dealing with supposed merger synergies. The first adjustment, shown on Yankee Schedule C-3.4 results in a \$5,825,000 reduction to test year expenses. The second adjustment, presented on Yankee Schedule C-2.0, effectively adds \$3.51 million of expenses back into the test year. Schultz and DeRonne PFT, p. 21.

OCC believes the \$5,825,000 adjustment to Yankee Schedule C-3.4 effectively calculates the difference between the actual test year balances in certain administrative and general accounts and the budgeted rate year balance in these accounts. Administrative and general accounts 920 through 935 are included in the analysis, with accounts 926 (Employee Pensions and Benefits), 928 (Regulatory Commission Expense), and part of account 925 (Injuries and Damages), specifically excluded from the adjustment. The difference between the 2002 forecasted balances of \$21,886,000 and test year actual balances of \$26,274,000 in the accounts being adjusted is \$4,388,000. Yankee then increased the effective \$4,388,000 adjustment by \$1.23 million for non-administrative and general operations synergies and \$207,000 for sales and marketing synergies, resulting in the overall reduction to test year expenses of \$5,825,000. Schultz and DeRonne PFT, pp. 21 and 22.

OCC asserts that Yankee has not shown, to its satisfaction, how the non-administrative and general expense merger synergies were calculated. Yankee merely stated that these synergies were identified by the operation, sales, and marketing teams. Further, Yankee states that these merger synergy savings are expected to take place in 2002. The savings are related to volume purchases, combining automatic meter reading operations together with combining economic development and community relation's functions. Schultz and DeRonne PFT, p. 22. OCC does not find this identification analytically rigorous. In its opinion, despite its requests it has not received any detailed support showing what is in the 2002 budgeted amounts. Yankee provided a listing of expense amounts by account and cost center. However, OCC believes that this is not satisfactory since it does not show specific costs or items included in the 2002 budget. Schultz and DeRonne PFT, pp. 22 and 23.

Based on its audit, OCC believes that the detail to support the 2002 budgeted amounts is so difficult to obtain that it is not feasible. This is because the budget is entered into the system by each individual cost control center. While the

budgeting system maintains the amounts that were entered, the detail behind how these accounts were determined is omitted. The detail in support of each individual budgeted item remains with the individuals at the cost control center level that are responsible for their respective cost control budgets. Yankee does not maintain supporting information for its budgeted accounts in a centralized location. There are no standardized requirements that the individual cost centers maintain their supporting documentation in any particular format. Schultz and DeRonne PFT, pp. 24 and 25.

OCC does not recommend any adjustments to the 2002 budgeted administrative and general amounts included in Yankee's merger synergy adjustment as found on Schedule C-3.4 of \$5,825,000. OCC recommends that the Department require Yankee to centralize the information supporting its budgets in the future if Yankee intends to employ budgeted amounts as support for adjustments. Schultz and DeRonne PFT, pp. 25 and 26.

OCC believes that Yankee's second merger synergy adjustment on Schedule C-2 is effectively adding \$3.51 million of expenses into the rate year. OCC believes analysis shows that in calculating the adjustment, Yankee began with the projected rate year budgeted expense reductions of \$5,825,000 as shown on Schedule C-3.4. An additional, \$1,767,000 of purported historic test year synergies was added to the \$5,825,000 resulting in a total amount of synergies of \$7,020,000. To this amount Yankee applied a 50% factor resulting in its addition to its adjusted rate year expenses of \$3.51 million. OCC reasons that the purpose of this Yankee adjustment is to flow to its shareholders 50% of the merger related synergies. OCC believes that Yankee wishes to include amounts in setting base rates on a going forward basis that it does not project it will incur.

OCC believes that Yankee determined its \$1,767,000 of historic test year level of merger synergies by beginning with actual test year expenses in A&G accounts 920 through 935. Yankee then removed merger related charges for the termination of its contract with IBM to determine an adjusted test year amount. The schedule then calculates the difference between the resulting amount and Yankee's test year budget. OCC asserts that no analysis was done to determine that each and every difference between the budget and actual results was a direct result of the merger. As a result of this methodology, Yankee's synergy adjustment not only includes a flow through of 50% of projected cost savings to its shareholders, but it also includes a flow through of 50% of any actual cost savings achieved by Yankee during the historic test year ended September 30, 2000. Schultz and DeRonne PFT, pp. 26 and 27. Due to its assertion of a faulty methodology of determining synergy savings, OCC removed the \$3.51 million added by Yankee stating that these are costs that Yankee does not project to incur in the rate year. Schultz and DeRonne PFT, p. 28.

The AG believes that the Department should reject Yankee's proposed merger synergy adjustment since it artificially increases its revenue requirements by \$3.5 million simply to generate additional income for shareholders. The AG asserts that this \$3.5 million merger synergy adjustment represents costs that Yankee does not expect to incur and, therefore, should not be included in base rates. The AG argues that the Department should reject Yankee's claim to retain any portion of the merger synergies reflected in the test year, which should be flowed to ratepayers. The AG believes that NU has already retained far more than its share of savings that have resulted from the merger and has retained 100% of all synergy savings from March 2000 to the present. In addition, since NU has allocated 49% of merger synergy savings to Yankee, NU shareholders will continue to retain the majority of merger savings into the future. Therefore, the AG concludes that the Department should write 100% of Yankee's savings into base rates as the ratepayers share of those savings. Brief, pp. 12 and 13.

c. Department Analysis

The Department analyzed the merger synergy adjustment starting with the baseline rate year revenue requirement as presented in column (a) on Schedule C-2.0 page 1 which includes \$7,020,000 of synergies. It is comprised of the following:

Rate year A&G Synergies	\$3,816,000
Rate year non-A&G Synergies	1,437,000
Test Year Synergies	1,767,000
Total	<u>\$7,020,000</u>

Schedule C-3.4

Since \$1,767,000 is reflected in the test year, the rate year adjustment is \$5,253,000 for a total of \$7,020,000. Yankee believes the mechanics of its adjustment shares the synergies equally between customers and shareholders. At the same time, it provides customers with the benefit of their 50% share immediately through lower rates. To effectuate this, Yankee removed the shareholders' 50% share (\$3.5 million) of the synergies from the baseline rate year revenue requirement. This adjustment generates an adjusted rate year revenue requirement that includes \$3.5 million of synergies, which Yankee asserts are the ratepayers' share. Schedule C-2.0, p. 1, column (c) and column (d).

The Department is concerned that the lack of support information on budgeted amounts is not easily accessed. It is obvious that each cost center manager has the

support information on budgeted amounts since it originated with each cost center manager. However, if this support information is not readily accessible it is not useful for both Yankee and outside auditors. The Department finds that this support information on budgeted amounts should be kept in a centralized location.

The Department segments Yankee's merger synergies into separate adjustments. The first having already taken place since it was included in the test year and as such is based on actual savings from the merger which is the \$5,825,000 reduction to actual historic test year expenses. The Department believes that ratepayers have already benefited from these test year synergy savings since Yankee's revenue request might have been higher. The Department finds that the second adjustment for \$3.51 million actually increases revenue requirements based on projected expenses that may or may not occur. The mechanics of Yankee's adjustment adds back the \$3.51 million into the test year, which serves to increase, projected rate year expenses by \$3.51 million.

The Department believes that proper ratemaking requires that base rates be set at the level that is projected to be realized during the test year. Yankee's adjustment for the \$3.51 million fails this test. Yankee computed the \$3.51 million adjustment with projected rate year budgeted expense reductions of \$5.825 million and added to this \$1.8 million of estimated historic test year synergies which results in a total amount of merger synergies of approximately \$7.02 million. Yankee's calculation of estimated historic test year synergies begins with its actual test year expenses and then removes charges for the termination of its IBM contract and an IBM contract adjustment to determine an adjusted test year expense amount. Yankee then considers the difference between this adjusted test year expense amount and its test year budget, which was prepared prior to the merger, as a merger synergy.

The Department finds this is not a realistic assumption that each and every difference between Yankees budget and its actual historic test year expenses are the result of the merger synergy savings. The Department agrees with OCC that an ESM should not flow to shareholders savings that have already been achieved in the rate year for which base rates are being set. The Department is satisfied with the allocation of merger synergy savings between NU and Yankee. The Department disagrees with the AG that NU has already retained far more than its share of savings that have resulted from the merger and has retained 100% of all synergy savings from March 2000 to the present based on the actual savings from the merger which is the \$5,825,000 reduction to actual historic test year expenses. The Department will not write 100% of NU/Yankee merger savings into base rates as the ratepayer's share of those savings as the AG requests. However, the Department adjusts Yankee's O&M expenses by disallowing Yankee's rate year synergy adjustment of \$3,510,000.

12. Marketing Expenses

[44] In its proposal, Yankee proposed a rate year adjustment for marketing expense of \$1,119,000. Schedule C-3.7. This amount is associated with the Company's planned increased marketing efforts to acquire new customers and to promote the system expansion efforts into previously unserved franchise areas. Seventy-five percent of those expenditures $((\$83,200 + \$755,753)/\$1,118,746)$ are marketing programs for residential, commercial and industrial customers, and the remaining 25% of the expenses are for estimated non-labor sales and marketing expenses, meetings and seminars with channel partners or customer groups, and database and mailing activities. Mahoney PFT, p. 20 and Responses to Interrogatories OCC-36 and OCC-335.

The OCC recommends that the Company's proposed adjustment of \$1,119,000 be recorded below the line because the expense is in direct conflict with Conn. Gen. Stat. § 16-19(d). The OCC's premise is that these costs promote the switching from an alternative fuel source to natural gas. Shultz and DeRonne PFT, pp. 33 and 34. Further, the OCC indicates that it is patently unfair for existing ratepayers to pay for incrementally higher costs related to the expansion program without receiving recognition in revenue requirements of the benefits of those costs. Brief, p. 60.

While the marketing initiatives described by the Company are reasonable for any company entering a new market, it is clear that those marketing activities are aimed at gaining customers currently served by other fuel sources. Conn. Gen. Stat. § 16-19d generally prevents the use of ratepayer funds to encourage fuel switching, recognizing that vendors of alternative fuel sources may lack monopoly ratepayers to subsidize similar programs. The statute contains no exceptions for marketing conducted in support of system expansion projects, even though such projects promote fuel diversity. [FN3] Because the marketing activities described by the Company do not differ in any meaningful fashion from those that would be funded by the Fuel Diversity Fund rejected elsewhere in this Decision, the Department rejects the proposed rate year marketing expenses. Based on the above, the Department reduces expenses by \$1,119,000.

13. Payroll Expense

[45] Yankee's test year payroll expenses total \$17,743,000. According to the Company's Application, it plans to hire 100 new employees in the rate year, which would increase payroll expenses by \$6,869,000 to \$24,612,000. [FN4] The \$24,612,000 rate year payroll expense comprises exempt and non-exempt employee salaries, union employee salaries, Northeast Utilities Service Company (NUSCO) payroll, planned new hires, escalation (raises) and offsets reflecting retirements, terminations,

transfers, capitalized labor and merger synergies. Exempt, non-exempt and union salaries are unchanged from the test year, pro forma year and rate year at \$27,477,000. The NUSCO payroll, the 100 new hires and escalation increased \$15,327,000 from the test year. Retirements, terminations, transfers, capitalized labor and merger synergies reduced the payroll expense by \$18,192,000. [FN5] Schedules C-3.19 and C-3.19a.

The Company adjusted its payroll expense by \$8,414,000 for synergy savings realized through its March 2000 merger with Northeast Utilities. Id. and Tr. 10/11/01, p. 1688. After the merger, 76 employees were transferred from Yankee to NUSCO. Schedule C-3.19b. Because that transfer happened in the middle of the test year, the pro forma adjustment had to be annualized to formulate the rate year calculation. Tr. 10/11/01, p. 1691. Twenty-six full-time equivalent Yankee employees either retired or were terminated during the test year. Schedule C-3.19b.

The Company stated that it expected to add 109 new employees, 100 in the rate year and nine in the following year, with all 109 salaries included in the rate year. Response to Interrogatory OCC-43; Tr. 10/11/01, p. 1694. Approximately one-third of the new employees will be designated to Yankee's system reliability at the request of the Department's pipeline safety audits. Tr. 10/11/01, pp. 1696-1701. As of July 1, 2001, 53 of the projected new employee positions were filled. Response to Interrogatory OCC-343 and Tr. 10/11/01, p. 1705. Of the new positions, 51 of the 109 are needed for Yankee expansion projects. Tr. 10/11/01, p. 1706.

OCC recommended a \$3,518,000 reduction in payroll expense limiting the number of post-test year additions to 52 employees, rather than the planned 109. Schultz and DeRonne PFT, pp. 34, 36. The exclusion of 57 employees is based on The consultants calculated unfilled positions as of July 2001. Id. This suggested reduction in new employees would reduce payroll expense by \$2,849,000 and affect escalation; therefore, OCC made a further adjustment of \$79,000. Tr. 10/18/01, p. 2232; Schultz and DeRonne PFT, p. 37. OCC's other substantial payroll adjustment is to the category of capitalized labor expense where it recommends a reduction in capitalized labor expense of \$590,000 based on the test year being two to three percentage points higher than Yankee's historical five-year average of capital versus capitalized expenses. [FN6] Schultz and DeRonne PFT, p. 38; Tr. 10/18/01, pp. 2239 and 2240. The net effect of OCC's adjustments would reduce Yankee's payroll expense from \$24,612,000 to \$21,094,000. Schultz and DeRonne PFT, Schedule C-1.

The AG supports OCC's recommendation to reduce payroll by \$3.5 million. Brief, p. 12.

The main contention in this case has been the inclusion of the proposed 109 new employees and how these new employees relate to the Company's proposed expansion projects. OCC and the AG recommend removing 57 employees from the rate year. The Company states that 33 of these new employees are needed for system reliability and approximately 20 employees are needed to replace retired and terminated employees. The Department finds that the addition of 53 employees (as of July 2001) should adequately fulfill the needs of Yankee's core business (business excluding expansion projects). Accordingly, the Department has determined the proposed 56 employee's to be hired after July 1, 2001 be designated as part of the Company's expansion projects and subject to the Departments review under the IERM discussed in Section II.I. System Expansion.

The Department is not making any adjustments for payroll expenses in this Decision. However, the Company is expected to justify \$2,741,000 in payroll and \$109,600 in escalation and \$439,250 for capitalized labor in its IERM annual review. [FN7] The \$2,741,000 expansion payroll expense requires an additional justification to payroll taxes. In the Company's rate year proposal, the ratio of payroll taxes to payroll expense was 8.3%. Schedule C-3.19. Using this ratio, payroll taxes of \$227,500 also needs to be addressed in the Company's first IERM review proceeding. [FN8] The total payroll amount subject to review in the IERM is \$2,638,500, or proposed expansion payroll plus escalation and taxes minus capitalized labor.

14. Public Liability Injuries and Damages Insurance

[46, 47] The Company requested \$317,000 annually for payments of public liability expenses. These expenses arise as a result of claims made against the Company for injuries and damages that are not covered within its \$1,000,000 insurance deductible. WP C-3.20f, line 15. Yankee's current reserve for injuries and damages is \$607,000. Schedule B-8.0, line 20; ADR-9 and ADR-10.

OCC indicates that the Company's reserve appears high and recommends that the \$317,000 of requested annual expense be removed from rate year expenses. Further, OCC would not be opposed to allowing Yankee to defer, as a regulatory asset, public liability payments made by the Company in excess of the \$901,000 reserve (includes reserve for workers' compensation expense). Brief, p. 71.

The Department notes that the Yankee's actual payment history over the three-year period ended September 30, 2000 was \$630,476, or an average of \$210,159 per year. This represented payment of claims while the Company had a \$200,000 deductible. Response to Interrogatory GA-289. During that same period, the Company's insurance carrier paid \$165,740 in claims that ranged from \$200,001 to \$1,000,000. Late Filed

Exhibit No. 88. This represents an actual annual average of \$55,247 for the three years. If Yankee had its current \$1,000,000 deductible during that three-year period, its annual average of actual payments would have been \$265,406 (\$210,159 plus \$55,247). Therefore, Yankee's reserve of \$607,000 represents approximately 2.3 times the annual three-year actual payment average. While the Department generally supports reserves, it finds that the Company's current reserve of \$607,000 appears excessive to its actual experience. Therefore, the Department disallows the Company's request for \$317,000 in annual expenses for public liability expenses. However, to the extent that actual payments during the rate period exceed the \$607,000 reserve, the Company is allowed to defer such payments as a regulatory asset to be considered in its next general rate filing.

15. Income Taxes

a. Interest Synchronization

[48, 49] The Department requires that interest expense be included in the calculation of a utility's state and federal income tax obligations. In Docket No. 99-09-03, the Department reiterated that it 'believed that adjusting pretax income by an interest component based on rate base times the allowed weighted cost of debt is more appropriate because it better 'synchronizes' allowed taxes, interest costs and rate base.' Decision dated May 25, 2000, p. 28. The Department has not found any reason to modify this determination. The size of a company's rate base, its cost of debt, and the percent of debt in its capital structure all enter into the interest synchronization model. The Department requires the following formula for the calculation of interest:

I Interest

R Rate Base

D Weighted Debt Percentage

$$I = R \times D$$

Yankee indicated that it used interest synchronization to determine the interest expense used in the calculation of its state and federal corporate income tax liabilities. Specifically, the Company reduced operating income by approximately

\$15,074,000 in its initial Application. Schedule WP C-3.25, p. 1.

The Department reduced the Company's proposed rate base by \$27,897,722 and adjusted the Company's proposed weighted cost of debt (short-and long-term) by 0.03%, from 3.88% to 3.91%. See, Sections II.B. Rate Base and Section II.G.2. Capital Structure, respectively. Accordingly, the interest synchronization results in a decrease of \$974,248 (\$27,897,722 times 3.91% less \$388,512,000 times 0.03%) in interest expense for tax purposes.

b. Connecticut Corporation Business Tax

The Company based its pro forma Connecticut Corporation Business Tax (CCBT) on its projected financial operations at the rate of 7.5%. The Department has adjusted the Company's proposed CCBT to reflect the adjustments to revenues and expenses, including interest synchronization, made by the Department in this Decision.

c. Deferred Federal Income Taxes

Yankee included (\$723,000) of deferred income taxes as a reduction of its pro forma operating expenses. The majority of this amount (\$635,000) is a result of timing differences between book and tax deferred hardship expenses. Schedule WP C-3.26, p. 1.

When the Department adjusts the Company's hardship expense, it increases the difference between Yankee's book and tax hardship expenses because the tax hardship expense remains the same. Therefore, an adjustment to book hardship expense requires an adjustment to deferred income taxes. The Department reduced the Company's hardship expense by \$150,312 and, therefore, will increase Yankee's deferred taxes by \$59,937 (\$11,273 + \$48,664). It is calculated as follows:

	State	Federal
Change in Hardship Expense	\$150,312	\$150,312
State Tax Rate	7.5%	
Deferred State Taxes	\$ 11,273	(11,273)
		139,039
Federal Tax Rate		35%

Deferred Federal Taxes \$ 48,664

In addition, the Department's adjustment to depreciation expense (see, Section II.D.5, Depreciation Expense) has implications for deferred income taxes. The decrease to depreciation expense of \$6,004,544 increases deferred income taxes by \$2,394,312 (\$6,004,544 X state and federal taxes). The total adjustment to deferred income taxes is an increase of \$2,454,249 (\$59,937 + \$2,394,312).

d. Federal Income Taxes

The Company based its pro forma Federal Income Tax (FIT) on its projected financial operations at a rate of 35%. The Department has adjusted the Company's proposed FIT to reflect the adjustments to revenues and expenses, including interest synchronization made by the Department in this Decision.

16. Other Tax Adjustments

a. Gross Earnings Tax

[50] Gas distribution companies are subject to the Connecticut gross earnings tax (GET). GET rates of 4% and 5% apply to residential customers and commercial/industrial customers, respectively. Yankee's initial Application projected a pro forma GET expense of \$13,304,000 for rate year expense. Schedule WP C-3.22, p. 2.

The Company calculated a 3.77% blended GET rate by dividing its rate year expense by total base revenues (\$13,304,000 divided by \$352,603,000) Schedule A-3. The Department accepts the Company's calculation.

The Department adjusted the Company's proposed GET to reflect the adjustments to revenues made by the Department in this Decision.

b. Property Tax Expense

[51] The Company used actual 1999 property tax assessments obtained October 1,

2000, and adjusted each town's mill rate to estimate rate year property taxes of \$10,148,000. Schedule C-3.23, p. 10; Tr. 10/11/01, p. 1681. Historically, the Department does not accept estimated mill rate projections and has always relied on known and measurable property tax data. The Company submitted its 2000 actual property taxes which were obtained October 1, 2001. Response to interrogatory GA-345. Yankee testified that this information was more appropriate and current property tax data. Tr. 10/11/01, pp. 1681 and 1682.

Two transactions Yankee consummated warranted adjustments to property taxes: the sale of land in the town of Bethel and a disputed tax settlement that was reached between Yankee and the Town of Meriden. Tr. 10/11/01, pp. 1683 and 1684. The Company resubmitted Schedule C-3.23 to adjust for these two transactions and submitted a revised test year property tax expense of \$9,303,000. Response to Late Filed Exhibit No. 76.

OCC recommends removal of the Bethel land sale and the tax settlement in Meriden. Also, the calculation of property tax expense should be based on the most recent actual assessments and mill rates. It advocates a property tax expense of \$8,245,560, a reduction of \$1,902,000 from the Company's Schedule C-3.23. Schultz and DeRonne PFT, pp. 59-61. With the exclusion of the Meriden settlement the OCC revised their pro-forma adjustment to \$8,936,100. Written Comments to the Draft Decision p. 16.

The Department reviewed Yankee's revised test year \$9,303,000 property tax expense and agrees with the Company's calculation. The Department also agrees with OCC's pro-forma adjustment of \$8,936,100. The Department finds that Yankee removed the Bethel land sale and the Meriden settlement in its resubmitted Schedule C-3.23. The adjusted test year and pro-forma year expenses need to be added together and divided by two to compute a rate year property expense of \$9,119,550. Therefore, the Department will make the corresponding adjustment of \$1,028,450 to property tax expense.

c. Property Tax Refund

The Company indicated that as a result of a settlement agreement with the City of Meriden regarding property tax assessments, it received a refund of \$9,950,505 on August 29, 2001. The Company's intent is to record the excess tax portion of the refunded amount of \$6,796,852 as a credit to the property tax expense account, and to record the interest portion of \$3,153,653 as a credit to the taxable interest account. Response to Interrogatory OCC-347. Yankee indicated that the refund was being treated as a prior period adjustment in accordance with paragraph 7.1 of the

Department's Uniform System of Accounts (USOA) for Gas Utilities. Tr. 10/12/01, pp. 1878 and 1879.

OCC and AG recommend that the refund of the past property taxes and interest be returned to ratepayers over a four-year period. Schultz and DeRonne PFT, p. 61; AG Brief, p. 13. Further, OCC suggests that the property taxes should be treated as an extraordinary item. Tr. 10/12/01, p. 1878.

The Department agrees with the Company that the settlement amount relates to transactions that occurred prior to the current calendar year. USOA § 7.1, p. 8. Further, the Department finds that amounts paid to the City of Meriden as a result of its reassessment of 1991 to 1994 taxes were not included in the property taxes in Yankee's 1992 rate case. Schultz and DeRonne PFT, p. 60; Tr. 10/18/01, pp. 2231 and 2232. Since, adjusting rates in the current rate case for the settlement is tantamount to single-issue retroactive ratemaking, the Department denies OCC's and AG's recommendation and will not consider the refund in the determination of the Company's revenue requirements in the current proceeding.

17. Uncollectibles

a. Hardship Programs

[52] In Docket No. 92-02-19, the Department allowed \$1,030,000 for the annual cost of the Matching Payment Program (MPP). See, Decision dated August 26, 1992. The Department also approved the Stipulation and Agreement between Yankee and OCC that allowed deferred hardship accounts and MPP to be offset by transition credits. See, Decision dated January 3, 1996 in Docket No. 92-02-19, Phase II, Section II.B.9. Transition Credit True-Up; Stipulation and Agreement, p. 2. Finally, the Department extended the use of transition credits as an offset to certain deferrals through September 30, 2000. See, Decision dated October 1, 1997 in Docket No. 92-02-19, Phase II, p. 2.

In its rate Application, Yankee requested an annual amortization of \$1,592,000 based on its projected pro forma deferred expense balance of \$6,369,000 amortized over four years. It then added \$3,198,000 of projected rate year expense to the amortization to produce rate year expenses of \$4,790,000 (\$1,592,000 + \$3,198,000). Schedule WP C-3.18.

OCC recommends that the Department disallow the \$4,790,000 annual expense because of Yankee's unusually high recent experience in deferring \$6,577,033 for the 10 months ended July 2001. This represents a 57% increase over the previous high. Further, OCC states that the Company's request for an annual recovery of the estimated Hardship Forgiveness (Hardship) and MPP Program activity expenses, in addition to amortization of past deferrals, is inconsistent with prior Department Decisions and the Company's prior allowed method. Based on OCC's calculation using the July 2001 deferred balance projected through December 2002, it recommends a reduction in test year expense of \$1,637,000 and an increase to rate base of \$2,362,000. Brief, pp. 50 and 51.

The Department recognizes that the Yankee's proposal is a departure from prior Decisions and Company practice. However, the Department also recognizes that the relief offered to the Hardship and MPP Programs through application of transition credits expired in September 2000, and is no longer available to the Company to minimize its deferred balances in these accounts. See, Section II.B.9. Transition Credit True-Up.

In the calculation of its reduction to rate year expenses, OCC fails to recognize any projected annual expense for Hardship and MPP write-offs. It uses a high average deferral figure to calculate the amortizable rate base item. Exhibit L&A-1, Schedule C-5. To estimate the annual impact of Hardship and MPP write-offs, the Department averaged the actual Hardship and MPP write-offs net of recoveries from October 1, 1996 to September 30, 2000. Fiscal year-1996 was not used in the calculation because the MPP write-offs were a negative \$2.1 million, which was not considered to be representative of actual experience. In its calculation, the Department excluded transition credits and allowable amortization from its calculation to more truly reflect Yankee's actual expense experience. This calculation resulted in four-year average balances of \$1,570,756 for MPP (\$6,283,025 divided by 4) and \$1,476,932 for Hardship write-offs (\$5,907,727 divided by 4). Late Filed Exhibit No. 86-SP01. The historical average Hardship and MPP expense from this calculation is an annual amount of \$3,047,688 (\$1,570,756 plus \$1,476,932).

The Department accepts the Company's calculation of deferred expense balance of \$6,369,000 at December 31, 2001, and the amortization period of four years. This yields an annual amortization of \$1,592,000. Schedule WP C-3.18. However, the Department finds that the allowable amount for annual write-offs should be the historical average of the aforementioned \$3,047,688. The Department, therefore, reduces Hardship and MPP Program annual expense by \$150,312 (\$3,198,000 less \$3,047,688).

In addition to the above, the Department reduced the deferred asset and

amortization expense amounts related to a number of deferred accounts including the aforementioned. See, Section II.B.9. Transition Credit True-Up.

b. Uncollectible Accounts Receivable Expense

[53] In its calculation of the Revenue Conversion Factor (RCF), the Company used an uncollectible accrual rate of 1.501%. This factor is derived by dividing actual test year expense of \$4,392,000 by test year revenues of \$292,647,000. Rate year revenues of \$382,323,000 were then multiplied by the accrual rate to arrive at rate year expense of \$5,738,000. Exhibit WP C-3.10. The actual test year expense is comprised of the Company's percentage estimates of collection on aged accounts receivable (Reserve Method). Tr. 10/12/01, p. 1813.

OCC indicated that in December of 1999, the 60 day, 90 day and 120+ days old accounts receivable were estimated to be 2%, 3% and 4% uncollectible, respectively. On January 31, 2000, the respective estimates were raised to 5%, 10% and 20% raising the estimated uncollectibles by \$563,175. Schultz and Deronne PFT, pp. 44 and 45. In OCC's opinion, estimated uncollectible expense is not representative of actual uncollectible write-offs net of recoveries. Rather than using the Company's Reserve Method, OCC used the actual five-year write-offs and calculated an uncollectible accrual rate of 1.219% of revenues or \$1.079 million less than the Company's request. Id., pp. 45 and 46. OCC states that use of an average takes into consideration that rates will be in effect for more than one year. Tr. 10/18/01, p. 2222.

The Department agrees with OCC that using actual net write-offs is a better measure of experience than using the Company's Reserve Method. In Yankee's previous rate case in Docket No. 92-02-19, the Department allowed an uncollectible accrual rate of 1.6051% based on the uncollectible expense in the test year. Decision, pp. 39 and 40. The Company's actual net write-offs in the test year, calculated by dividing test year net write-offs of \$3,008,610 by test year revenues of \$307,447,245, yields a test year accrual rate of .9786%. Response to Interrogatory GA-217. However, the Department notes that in 1999, the Company experienced the high rate of 1.995% caused by cleaning out old account balances prior to implementing a new customer information system. Late Filed Exhibit 84; Tr. 10/25/01, pp. 1815 and 1816.

Because the test year accounts receivable did not contain old balances, the Department finds that these account balances are not representative of the Company's actual experience. Therefore, the Department agrees with OCC and uses a five-year average of net write-offs compared to annual revenues of 1.225% determined as follows:

Year	Net Write-Offs	Revenues	Percent
1996	\$3,130,344	\$339,044,706	0.923%
1997	\$3,596,135	\$318,953,114	1.127%
1998	\$3,446,939	\$283,838,800	1.214%
1999	\$5,499,235	\$275,619,086	1.995%
2000	\$3,008,610	\$307,447,245	0.979%
Totals	\$18,681,263	\$1,524,902,951	1.225%

Late Filed Exhibit No. 84;

Response to Interrogatory GA-217

Using the difference in uncollectible accrual rate of 0.276% (1.501%- 1.225%) applied to pro forma rate year revenues of \$411,547,000 yields a reduction to Yankees uncollectible expense of \$1,135,870. Accordingly, the Department will reduce Yankee's uncollectible expense by \$1,135,870.

The Department also decreased the Company's pro forma revenues by \$60,625,178 in Section II.C. Revenue Adjustments. Accordingly, the Department will decrease the Company's pro forma uncollectible expense by \$742,658 (1.225% times \$60,625,178). The total uncollectible expense adjustment is \$1,878,528 (\$1,135,870 plus \$742,658).

E. REVENUE CONVERSION FACTOR

[54] The Department employs a revenue conversion factor (RCF) 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. The Company used the following rates to calculate an RCF of 1.75538:

Connecticut Corporation Business Tax (CCBT) Rate	7.5000%
Federal Income Tax (FIT) Rate	35.0000%
Weighted Gross Earnings Tax (GET) Rate	3.7732%
Uncollectible Rate	1.5010%
Thus, the calculation is:	
Revenue Change	100.0000%
Less: CCBT (7.5% times 100%)	7.5000%

Less: FIT (35% times 92.5%)	92.5000%
	32.3750%
Times: GET (100% minus 3.7732%)	60.1250%
	96.2268%
Adjusted by: Uncollectible factor: (1.501% divided by 96.2268% plus 100% divided into 57.8564%)	57.8564%
RCF -- Reciprocal of 56.9678%	56.9678%
	1.75538

Schedules A-2 and A-3

1. Allowed RCF

In the calculation of Yankee's RCF for this proceeding, the Department will use the following rates:

GET Rate	3.7732%
Uncollectible Expense	1.2250%
CCBT Rate	7.5000%
FIT Rate	35.0000%

Accordingly, the Department finds that the 1.75070 RCF, calculated in the table below, is reasonable.

Revenue Change	100.0000%
Less: GET	3.7732%
	96.2268%
Less: Uncollectible Expense	1.2250%
	95.0018%
Less: CCBT (7.50% times 95.0018%)	7.1251%
	87.8767%
Less: FIT (35.00% times 87.8767%)	30.7568%
Net Income Percentage of Total Revenue	57.1199%
Revenue Conversion Factor -- Reciprocal	

of 57.1199%

1.75070

2. Uncollectible Rate

In Section II.D.17.b. Uncollectible Accounts Receivable Expense, the Department found that 1.225% represents a reasonable uncollectible write-off percentage. Because uncollectible expense is a function of revenues, the Department believes that when adjusting revenues, it is appropriate to make comparable adjustments to uncollectible expense. Accordingly, the Department will incorporate this bad debt percentage into the Company's RCF.

F. GAS COST

[55] The Company's actual test year gas costs were \$154,753,000 based on sales of 31,930,585 Mcf. Schedule E-3.4. The test year gas costs were based on the individual monthly gas costs ending September 2000. The Company compared the test year monthly gas cost to the proposed rate year gas costs. This calculation resulted in gas cost increase of \$73,399,000 for the rate year. Responses to Interrogatories GA-256 and GA-260. The Company proposed a \$228,152,000 gas cost for the rate year, based on an annualized sales forecast of 32,600,459 Mcfs. Schedule E-3.1. These gas costs were determined using a summer price of \$3.99 and \$4.85 per Mcf and includes the cost of gas for firm, interruptible and special contract customers. Response to Interrogatory GA-256. The Company used a natural gas forecast for the rate year prepared by Energy Ventures Analysis, Inc. Response to Interrogatory GA-256; Schedule C-3.1; Late Filed Exhibit No. 64. Yankee's asset management agreement ended on October 31, 2001 and the Company began managing its own gas supply portfolio. The Company also reorganized its gas supply management staff. It hired a new gas supply manager whose primary function will be to negotiate new gas supply contracts for the heating season and sell unused capacity on the open market. Andrukiewicz PFT, p. 9.

The Department requested an update of the gas costs based on forecasted gas costs and normalized monthly gas consumption data for the rate year. For the exhibit, the Company used the NYMEX futures price of gas as reported on October 10, 2001 for each month during the rate year. The Company stated that when it updated the New York Mercantile Exchange (NYMEX) commodity cost of gas used for the projected rate year, the cost of gas ranged between \$2.70 Mcf and \$3.361 Mcf. The updated costs include the cost of gas associated with the customers the Company expects to add to the system under its expansion program. Late Filed Exhibit No. 64. With that update, the total gas cost for the rate year was projected to be \$170,210,214. The Company indicated that it does not expect gas prices to retrace the record levels that occurred during the test year. This is because the economy has slowed, storage levels have increased since the 2000 levels, and there has been an increase in

production. Response to Interrogatories GA-261 and GA-263; Schedule E-3.4.

OCC supports Yankee's decision to manage its own gas supply function, rather than use an outside asset manager. However, OCC believes that Yankee's proposed gas cost is too high. Gas costs influence the Company's revenue requirement through its allowance for O&M expenses. Accordingly, OCC supports the more current gas cost estimate of \$170,210,214. OCC recommends that the Department initiate a generic proceeding to consider commodity price stabilization programs. Brief, pp. 144-151. Neither the AG nor CIEC addressed the question of gas costs.

The Department believes that the gas costs the Company used for the rate year were the result of an anomaly in the natural gas market. The gas cost spike resulted from several factors. During 1998 and 1999, the domestic gas drilling rig count dropped to all time lows, causing a short fall in production during the year 2000. Additionally national storage levels during the calendar year 2000 were significantly lower than in previous years. The addition of a strong economy further exacerbated the supply and demand situation in the national natural gas market.

The Department believes that the natural gas market that existed prior to the rate year is different from the test year gas market. This is due to a number of factors: the increase in drilling rigs during 2001, weaker economy, and a greater level of storage injections in 2001 or 2000. As a result of these factors, the Department believes that the cost of gas will be lower in the rate year than the test year. Therefore, the Department believes that the Company's proposed rate year gas cost is overstated. The Company developed the gas cost used in its filing before the economy began to significantly cool down. Since the national gas market has changed from the test year to the impending rate year, the projected rate year gas cost should be based on the latest available data. Based on the aforementioned, the Department finds that current gas cost estimate of \$170,210,214 is the appropriate amount to use for the rate year.

In the revenue section of this Decision, the Department stated that it would not accept the Company's use of a 20-year normalization and 30 years should be used for the determination of the normalized annual gas consumption. To account for the adjustment in the Company's HDD normalized sales forecast for the rate year, the Department added 315,000 Mcfs. The Department increased the total normalized gas consumption from 32,600,459 Mcf, to 33,268,670 Mcf (32,600,459 Mcf + 315,000 Mcf + 353,211 Mcf). According to the Company, increasing the normalized gas consumption would result in an increase to the gas costs of \$952,946. Response to Interrogatory OCC-313. Further, the system expansion added 353,211 Mcfs of consumption to Yankee's system. Therefore, the total gas costs will need to be increased as a result of the change in the normalized gas consumption projected for the rate year. The Department

accepts a total normalized annual gas consumption of 33,268,670 Mcf, and a rate year gas cost of \$167,300,000 ($32,600,459 \text{ mcf} \times \$5.066 + \$1,171,633 + \$952,946$). The Department developed this cost of gas by adjusting the 33,363,002 Mcf of consumption in Late Filed Exhibit 64 to match the consumption the Company's projected sales of 32,600,459 Mcf shown in Schedule C-3.1 p. 2. To make the adjustment, the Department then multiplied the volume of 32,600,459 Mcf times the unit cost of gas used in Late Filed Exhibit 64 of \$5.066 ($\$169,038,581 / 33,363,002 \text{ Mcf}$). The Department then added the cost of gas associated with the system expansion of \$1,171,633 and the cost of gas associated with the change in the weather normalization of \$952,946. This results in a reduction to gas costs of \$60,852,000. Since the price of gas the Company purchases fluctuates on a daily basis, the semi-annual PGA will capture fluctuations in the gas prices above and below this estimate. The natural gas market has stabilized considerably of its own accord since the fall and winter of 2000/2001. The Department will continue to observe the market in the future.

In Yankee's last rate case Docket No. 92-02-19, the Department approved a cost of gas of \$4.2519 Mcf or \$.42519 ccf. This cost of gas included the cost of gas for firm, interruptible and special contract customers. In the instant docket, the Department approves the projected cost of gas of \$167,300,000 and the projected consumption of 33,268,670 Mcf for the rate year. The new base cost of gas will be \$5.0288 Mcf ($\$167,300,000 / 33,268,670 \text{ Mcf}$), which is equal to \$.50288 ccf.

G. CAPITAL AND RATE OF RETURN

1. Introduction

[56] In Federal Power Commission v. Hope Natural Gas Company, 320 US 591 (1944), 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 calculate a rate of return on rate base that is appropriate for Yankee'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 determined 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

[57-59] The capital amounts and capitalization ratios in the Company's proposed capital structure were based on debt and equity balances reported on Yankee's books starting with test year levels as of September 30, 2000, adjusted forward to the mid-point of the rate year (June 30, 2002). Key assumptions included long-term debt issuances totaling \$105M, budgeted income for 2001 and 2002, no common dividend payments, and an equity infusion of \$13.5M from NU at the end of 2002. McHale PFT, pp. 6-9, Schedule D-1.0. The Company's ratemaking capital structure with proposed cost rates is shown below.

Class of Capital	Amount	% of Total	Cost	Weighted Cost
5p Long-Term Debt	\$237,348,000	52.71	7.37%	3.88%
Total Debt	<u>\$237,348,000</u>	<u>52.71</u>		<u>3.88%</u>
Common Equity	\$212,943,000	47.29	11.78%	5.57%
Total Capitalization	<u>\$450,291,000</u>	<u>100.00</u>		<u>9.45%</u>

OCC's recommended capital structure, including suggested cost rates, is shown below. Hill PFT, Schedule 11.

Class of Capital	Amount	% of Total	Cost	Weighted Cost
5p Short-Term Debt	\$ 36,023,000	8.00	4.50%	0.36%
Long-Term Debt	\$201,325,000	44.71	7.37%	3.30%
Total Debt	<u>\$237,348,000</u>	<u>52.71</u>		<u>3.66%</u>
Common Equity	\$212,943,000	47.29	10.125%	4.79%
Total Capitalization	<u>\$450,291,000</u>	<u>100.00</u>		<u>8.45%</u>

Aside from the equity cost rate issue, the significant difference between the two proposed capital structures concerned short-term debt treatment. The Company's proposed capital structure excluded short-term debt for purposes of calculating the ROR. OCC supported a capital structure in which short-term debt comprised 8% of

total capital, keeping the common equity balance and capitalization ratio at the levels requested by the Company. Hill PFT, pp. 15- 20, Schedule 2, p. 4. The treatment of short-term debt costs for ratemaking purposes is discussed below.

3. Short-Term Debt Costs

In proposing to exclude short-term debt from the capital structure, the Company sought to recover costs associated with short-term financing through allowance for funds used during construction (AFUDC). In support of this proposal, Yankee referred to the magnitude and scope of the Company's new infrastructure plan, the unfeasibility of funding the construction of long-term capital given the level of short-term credit capacity available to Yankee, the level of short-term debt itself which is anticipated to be less than half, on average, of construction work in progress (CWIP) going forward, and the AFUDC formula assumption that short-term debt is first used to fund CWIP. McHale PFT, pp. 6-9; Tr. 10/19/01, pp. 2559-2565.

OCC argued against excluding short-term debt from the ratemaking capital structure. It cited the extent to which short-term debt has been utilized by Yankee in the past, the lack of evidence buttressing the Company's claim that its use of short-term debt will actually decline during the rate year, and the inapplicability of the AFUDC rate to appropriately accomplish short-term interest cost recovery. Hill PFT, pp. 16-18.

In support of its proposal to exclude short-term debt from the ratemaking capital structure, the Company specifically referenced the formulas on FERC Form No. 2, presented in Exhibit DRM-2, as the recovery mechanism for short-term debt costs. McHale PFT, p. 8; Tr. 10/19/01, p. 2570. Consequently, the Department closely examined Yankee's interpretation and implementation of those formulas to ensure that AFUDC rates used to capitalize the cost of CWIP-associated funds conformed with FERC requirements.

The Department's review of the two formulas in Exhibit DRM-2, the gross rate for borrowed funds and the rate for other funds, finds that the FERC methodology was devised to recognize the interrelationship between capital utilized for rate case and construction purposes. In this way, the formulas work to determine an AFUDC rate regardless of whether short-term debt is less or greater than CWIP. In the case of short-term debt less than CWIP, the Company's understanding and description of the FERC formulas to recover short-term debt costs was appropriate and consistent. In the reverse scenario, however, Yankee testimony was equivocal. While stating the FERC approach mathematically calculated an AFUDC rate when short-term debt exceeded CWIP, Company witnesses offered varying testimony regarding the adequacy of that

rate. They alternately testified that the formulas would and would not collect the appropriate level of short-term debt supporting CWIP. Tr. 10/19/01, pp. 2569-2580. In analyzing the Company's proposed capitalization of test year construction costs, the Department noted that the rate shown for other funds in Exhibit DRM-2 did not match the rate resulting from application of the FERC formula. To resolve these other issues related to test and rate year AFUDC rates, the Department requested Late Filed Exhibit Nos. 108, 128, and 129.

Based upon the review of those late filed exhibits, the Department finds that the Company has not satisfactorily demonstrated its ability to utilize this approach. Given the two alternative recovery mechanisms, the Department concludes that the recovery of short-term debt costs is more likely to be accurately accomplished by its inclusion, rather than exclusion, in the capital structure. Therefore, for ratemaking purposes the Department will accept the short-term debt amount of \$18,107,000 and short-term debt cost rate of 4.72% in Late Filed Exhibit No. 108.

4. Cost of Long-Term Debt

The 7.37% cost of long-term debt was not contested in this proceeding, and is found to be acceptable for ratemaking purposes.

5. Cost of Equity

a. Summary of Company's Testimony

[60, 61] The Company's cost of equity testimony was prepared by David R. McHale, Vice President and Treasurer of NU and Yankee. Mr. McHale employed two measuring techniques to estimate the Company's cost of equity, discounted cash flow (DCF) and risk premium. The DCF methodology established a ROE of 11.31% absent risk adjustment. The risk premium methodology produced an investor-required ROE of 12.16%. Mr. McHale endorsed the risk premium approach as stronger than DCF for purposes of this proceeding. However, in recognition of the inherent strengths and weaknesses of each methodology, and in deference to Department precedent and preference for the DCF as a primary indicator, he gave equal weight to each approach. Responses to Interrogatories GA-209 and OCC-269, pp. 2 and 3. An eight basis point risk adjustment was made to account for Yankee's lack of a weather normalization adjustment (WNA), increasing the DCF to 11.39%. The Company's final recommended ROE, giving 50% weight to each methodology, was 11.78%. [FN9]

As Yankee's stock is not publicly traded, the Company's DCF calculations were based on a proxy group of gas distribution companies. Key among the proxy group inclusion criteria were that a company actually trade as a distribution company and not be involved in price-distorting merger activity. Based on the selection criteria and an independent review by Morgan Stanley Dean Witter and Salomon Smith Barney, a total of nine proxy group companies were chosen. McHale PFT, pp. 12 and 13; Responses to Interrogatories OCC-268, OCC-269, and OCC-272. These companies with their stock ticker symbols were Cascade Natural Gas Corporation (CGC), Laclede Gas (LG), New Jersey Resources (NJR), NICOR (GAS), Northwest Natural Gas (NWN), Peoples Energy (PGL), Piedmont Natural Gas Company (PNY), South Jersey Industries (SJI), and WGL Holdings (WGL).

Details underlying the DCF cost of equity of 11.39% included: an average dividend yield of 4.84% for the proxy group; forward growth rates based on analyst forecasts of five-year earnings growth published by Value Line and First Call that averaged 6.32%; a yield adjustment [FN10] equal to half the indicated average forward growth rate to incorporate for investor expectations of quarterly dividend increases; and the eight basis point risk adjustment. [FN11] The earnings growth projections from Value Line were dated June 22, 2001, while those from First Call were as of June 25, 2001. [FN12] The average earnings growth estimate forecast by Value Line for the proxy group was 7.61%, while First Call's (which included the Zacks' estimate for CGC) was 5.03%. McHale PFT, Exhibits DRM-4 and DRM-6. The dividend yield calculation was based on the average monthly high and low stock price for each proxy group company over the six-month period ending May 2001. McHale PFT, Tables DRM-4 and DRM-5. The risk adjustment allocated 25 basis points to the DCF-calculated ROE for three companies in the proxy group (i.e., NJR, PNY, and SJI) with WNAs as part of their rates. Since the adjustment was applicable to one-third of the companies in the proxy group, the net effect was an eight basis point adjustment to the DCF-indicated cost of equity. McHale PFT, Table DRM-7, pp. 19-20

Based on the historical average difference between the returns on large company stocks and long-term corporate bonds as reported in the Ibbotson Associates SBBI 2001 Yearbook over the 30-year period 1971-2000, Mr. McHale concluded that the incremental yield, or risk premium, required by investors for equity ownership, is 4.9%. The cost of debt was specified at 7.26%, equal to the 5.53% average yield on 30-year treasury bonds over the six-month period ending May 2001, increased by the credit spread of 1.73% for a low 'A'-rated 30-year utility bond as stated by Bridge Information Systems as of June 25, 2001. The risk premium of 4.9% added to the 7.26% cost of debt results in the ROE of 12.16%. McHale PFT, pp. 21 and 22.

b. Summary of OCC's Testimony

OCC's cost of equity testimony employed several measuring techniques to analyze Yankee's cost of equity, DCF, capital asset pricing Model (CAPM), modified earnings-price ratio (MEPR), and market-to-book ratio (MTB). In summarizing the results of the DCF and other models (collectively, the non-DCF techniques), OCC concluded that Yankee's ROE was equal to 10.125%, the midpoint of his summary cost of equity range of 9.75% to 10.50%. Hill PFT, p. 39. OCC's DCF analysis determined a 10.49% cost of equity. The CAPM produced an equity cost range of 7.26% to 8.28%. The MEPR produced an equity cost range of 9.60% to 10.39%, and the MTB produced an equity cost range of 10.12% to 10.44%. OCC testified that the range 9.75% to 10.50% was neither pegged to a particular result, nor tied to any kind of mathematical construct; rather, it was result of professional judgement and a function of all four methodologies. Tr. 10/19/01, pp. 2728, 2731, and 2733.

OCC's DCF cost of equity was determined using a similar-risk sample group, akin to the proxy group utilized by Yankee. The criteria for the gas distribution firms included by OCC in its similar-risk sample group were as follows: a continuous financial history reported by Value Line; at least 90% of operating revenues generated by gas operations; investment-grade bond ratings of 'A' or below; and no upward stock price shift due to merger activity. A total of seven companies were selected based on these criteria: CGC, NJR, NWN, PNY and SJI; and AGL Resources (ATG), and Atmos Energy Corporation (ATO). Hill PFT, pp. 22 and 23. The first five companies were included in Mr. McHale's proxy group; the latter two were unique to OCC's similar-risk sample group.

The heart of OCC's DCF analysis consisted of a long-term sustainable growth rate analysis for each company in the similar-risk sample group considering Value Line's forecast returns on common equity, earnings and dividends per share, number of common equity shares outstanding, and estimated growth in book value, earnings, and dividends; Zacks projected earnings growth rates; as well as historical growth trends in book value, earnings, dividends, common shares outstanding, and average sustainable growth over the most recent five-year period. The average long-term sustainable growth rate estimate for the similar-risk sample group, based on internal growth due to earnings retention and external growth from anticipated sales of stock, was judged equal to 5.65%. Hill PFT, Schedule 4, p. 1.

The average dividend yield for the similar-risk sample group was 4.84%, identical to Mr. McHale's proxy group dividend yield. Hill PFT, Schedule 5. Combining the average yield with the average sustainable growth rate estimate established a 10.49% the DCF cost of equity capital. Hill PFT, Schedule 6.

The non-DCF techniques were described by Mr. Hill as 'corroborative analyses.' Hill PFT, p. 39. Averaging the high and low results of each corroborative analysis (MEPR,

MTB, and CAPM) produced an equity cost rate range of 9.0% to 9.7%, midpoint at 9.35%. Eliminating consideration of CAPM produced a range of corroborating results from 9.86% to 10.42%, midpoint at 10.14%. The average of 9.35% and 10.14% is 9.75%, precisely the value that defines the bottom end of OCC's summary cost of equity range.

c. Cost of Equity Analysis

The Department carefully considered the testimonies of the Company and OCC and is confident that the best solution to its cost of equity capital requirements exists within the framework of the DCF model. This conclusion is based on the strength of various elements in the separate DCF analyses of the two testimonies, and is also a function of the weaknesses evident among other methodologies used to assess Yankee's cost of equity.

i. Critique of the Risk Premium Approach

Some problems with respect to quantifying the risk premium were identified by Company witness David McHale. They included the period of time over which the stock-bond yield spread should be measured, and the question of what average bond maturity should be used. Response to Interrogatory GA-209. Another issue addressed by OCC's witness Stephen Hill concerned the question of which debt and equity securities should be used. Hill PFT, Schedule 14. Another weakness of the risk premium approach concerns the value of historical average risk premium data in time of economic uncertainty. Mr. McHale affirmed this problem when, by reference, he stated '[t]hey are a less than great predictor of the future, no question about it.' Tr. 10/19/01, p. 2657. Another drawback to the methodology, one of potentially significant impact and of concern to the Department, involves the failure of historical average risk premiums to account for changes in the riskiness of debt versus equity may be occurring over time. Public Utilities Reports Guide 6, 'Utility Rates,' pp. 6-13. Mr. McHale granted that the extent to which the risk premium model looks backward and makes observations from historical data is not one of its strengths. Tr. 10/19/01, p. 2632. These issues signal a major problem with the risk premium approach.

In the context of validating the risk premium outcomes of various averaging periods against the DCF method, Mr. McHale selected the 4.9% result corresponding to the 30-year period. He did not recommend the risk premium of 5.95% associated with a 25-year averaging period because it appeared 'less reasonable' with respect to the return on common equity level it would produce. Response to Interrogatory OCC-276; Tr. 10/19/01, pp. 2611 and 2612. From Mr. Hill's perspective, it is clear that he

would place the bottom end of the risk premium at not less than 2.0%. Hill PFT, p. 55. Therefore, based on the testimony of the cost of capital witnesses, it appears that they have defined a risk premium associated with Yankee's common equity in the range of 2.0% to 6.0%.

This range, while plausible, is very wide, consistent with the underlying volatility of the risk premium and the many interpretations of how it may be measured. Selecting a specific value within the range is an extremely subjective exercise, even under the artificial assumption that the risk premium is constant over time. Response to Interrogatory GA-381; Tr. 10/19/01, p. 2633. When it is considered that the actual risk premium over the next year, 10 years, or 30 years could be far different compared to the historical average risk premium associated with the 30-year time period evaluated by Mr. McHale, the potential error in ascribing 50% weight to the approach in determining the Company's cost of equity becomes unacceptably high. Tr. 10/19/01, pp. 2645 and 2646. Mr. McHale asserted that it cannot be known what the future risk premium will be. Id., p. 2647.

It appears Yankee's main argument in support of the 4.9% risk premium is that the 30-year time period used for its measurement encompasses sufficient economic cycles, and the 12.16% return on equity it produces is reasonable. McHale PFT, p. 22. From the Department's perspective, there is no reason to conclude that the 30-year period chosen by Mr. McHale is more appropriate than any other 30-year period, which would have produced markedly different results. With respect to the second point, the idea that 12.16% is a reasonable return on equity is entirely Mr. McHale's opinion. It is in that assessment wherein resides an enormous amount of judgement. In contrast, the degree of subjectivity under the DCF methodology (e.g., in determining the prospective growth rate) can be minimized by carefully assembling a large enough proxy group, much like a portfolio of stocks, in which the bias, or errors, of judgement are diminished via diversification. There is no such mechanism in the risk premium analysis.

For all the reasons discussed herein, and absent any attempt to transform historic risk premium data into a meaningful forward-looking estimate, the Department finds that it would be inappropriate to assign any weight to the risk premium methodology in determining the cost of equity capital in this proceeding.

ii. Critique of the Non-DCF Techniques

The Department finds that OCC's non-DCF techniques, or corroborative analyses, fail in that they seemingly do not support, agree with, or confirm anything. Even when the CAPM results, which are described as 'way too low' and 'outside the range of

anything [Mr. Hill] would consider reasonable,' are eliminated from consideration, the corroborating range that ensues is still entirely below the DCF result of 10.49%. Tr. 10/19/01, p. 2726; Hill PFT, p. 39.

OCC is clear in written testimony that the DCF approach is its 'primary indication of the cost of equity capital.' Hill PFT, p. 39. Nevertheless, it is difficult to consider the non-DCF ranges, with accompanying narrative, and conclude that those results did not receive substantial consideration in determining the recommended cost of equity. At 10.125%, OCC's recommended cost of equity falls in the midst of the range corresponding to the MEPR analysis. It also defines the very bottom end of the MTB analysis, and appears unrelated to the primary indication of the cost of equity capital. Additionally, the non-DCF methodologies lacked the scope, depth, and detail of OCC's DCF analysis. The apparent inclination to allow the cost of equity recommendation to gravitate toward non-DCF results, and to characterize the DCF result as overstated, was a contradictory aspect of OCC's testimony. For these reasons, the Department finds that it is ill-advised to seriously consider results from the non-DCF techniques in this proceeding.

iii. The DCF Solution

[62] The applicable return on equity will be determined based upon the proxy group of gas distribution companies assembled by Yankee in concert with two of its investment banks. Also, it will use the analytical construct employed by Mr. Hill to evaluate the rate of projected growth in the DCF model.

The Company's growth rate analysis relied exclusively on earnings growth rate projections published by Value Line and First Call. The first source forecast average earnings growth for the proxy group of 7.6%; the second source estimated 5.0%. McHale PFT, Table DRM-6. The Department recognizes that Mr. McHale included the First Call earnings growth projections as a way to temper and make more realistic the robust assessments included in Value Line. However, to simply rely on earnings growth estimates as a proxy for expected growth in dividends and capital appreciation is inadequate. For example, there is no reason for investors to expect that earnings growth much in excess of book value growth will be sustainable, or representative, over a long-term investment horizon, just as dividend growth in excess of earnings growth would not last for very long unless a company wanted to continuously dilute shareholder value. Earnings volatility is yet another reason to avoid sole reliance on forecast earnings growth rates as an indicator of cash flow growth. The divergent earnings growth predictions made by Value Line and First Call illustrate this problem.

The Company agreed that long run earnings growth is tied to the anticipated return on book equity, and thus on the growth rate of book value per share. Response to Interrogatory GA-112. Therefore, one potentially reasonable approach for determining investors' growth rate expectation is to include Value Line's projected book value growth rates with the earnings growth estimates. The following table shows the five-year earnings growth rate forecasts included in Mr. McHale's Table DRM-6 with Value Line's five-year book value growth rate forecasts. Exhibit DRM-4, pp. 6, 9, 11-13, 15-16, 18, and 22. The average annual growth rate for the proxy group with the inclusion of the book value growth rates is 6.16%.

.ps 7.6

Company	Value Line Earnings Growth (%)	Value Line Book Value Growth (%)	First Call Earnings Growth (%)	Average Annual Growth (%)					
5p									
CGC	7.00	4.00	5.00	5.33					
LG	6.50	3.50	2.00	4.00					
NJR	7.50	7.50	7.30	7.43					
GAS	6.50	7.00	6.00	6.50					
NWN	8.50	4.00	4.50	5.67					
PGL	8.50	7.50	5.50	7.17					
PNY	8.00	7.00	5.00	6.67					
SJI	7.50	6.00	4.50	6.00					
WGL	8.50	6.00	5.50	6.67	7.61	5.83	5.03	6.16	
				Average					

5p

Source: McHale PFT, Table DRM-6, and Exhibit DRM-4.

The analysis portrayed above is simple and offers insight into the expected growth rate in the DCF model. However, it relies exclusively on projected information and gives no consideration to actual, past earnings performance.

Mr. Hill's DCF growth rate analysis was much more comprehensive. It considered recent sustainable growth and historic trends in earnings, dividends, and book value, and evaluated long-term sustainable growth based upon the determination of an internal growth rate from earnings retention and growth from external sources. The following table provides a summary of Mr. Hill's long-term sustainable growth synopses for the proxy group companies. The average sustainable growth rate estimate for all the distribution companies is 5.66%. [FN13]

.ps 7.6

Company	Internal Growth (%)	Expected Share Growth (%)	M/B	External Growth (%)	L/T Sustainable Growth (%)	
5p						
CGC	5.25	1.00	1.63	0.32		5.57
LG	4.00	1.25	1.55	0.34		4.34
NJR	6.25	-0.25	1.94	-0.12		6.13
GAS	7.00	-0.75	2.26	-0.47		6.53
NWN	5.25	0.25	1.31	0.04		5.29
PGL	5.25	0.00	1.75	0.00		5.25
PNY	5.50	0.75	1.84	0.32		5.82
SJI	5.00	2.25	1.67	0.75		5.75
WGL	6.00	0.75	1.68	0.26	6.26 Average	5.66
5p						

Source: Hill PFT, Appendix C, Schedule 4, p. 1, Late Filed Exhibit No. 132.

The Department examined investor growth rate expectations for the proxy group companies using the same data and sustainable growth format employed by Mr. Hill. The summary of that analysis is shown in the following table. Differences between the Department's conclusions and those of Mr. Hill appear in bold.

.ps 7.6

Company	Internal Growth (%)	Expected Share Growth (%)	M/B	External Growth (%)	L/T Sustainable Growth (%)
5p					
CGC	5.00	1.50	1.63	0.47	5.47
LG	4.00	1.25	1.55	0.34	4.34
NJR	6.75	0.00	1.94	0.00	6.75
GAS	7.00	-0.50	2.26	-0.32	6.69
NWN	5.25	0.25	1.31	0.04	5.29
PGL	6.00	0.00	1.75	0.00	6.00
PNY	6.00	0.75	1.84	0.32	6.32
SJI	5.25	2.25	1.67	0.75	6.00

WGL 6.00 1.00 1.68 0.34 6.34 Average 5.91
5p

Source: Mr. Hill's analytical DCF construct modified per the Department's review of Value Line's data in Exhibit DRM-4.

A comparison of the two evaluations shown in the tables above reveals a substantial degree of agreement. Overall, the average growth rate resulting from the Department's analysis is 25 basis points greater than Mr. Hill's. While the difference is not very large, the Department believes that 5.91% is a better estimate of projected growth based on the proxy group of nine gas distribution companies than 5.66%. Mr. Hill acknowledged that his DCF results could be understated given the role of judgment and the inexact nature of the estimation process. Tr. 10/19/01, p. 2732.

With an average dividend yield for the proxy group of 4.85%, and a projected growth rate of 5.91%, the adjusted dividend yield for the proxy group is 5.0%. [FN14] Therefore, the DCF-indicated equity cost rate, absent risk adjustment, is 10.91%. The Company calculated an eight-basis point adjustment to account for its lack of a WNA. Upon review of testimony and evaluation of the Company's risk characteristics relative to the proxy group, both in terms of the S&P financial targets ratios and operating data profiles, the Department finds that this small adjustment is appropriate. Tr. 10/19/01, pp. 2589-2606; Response to Interrogatory OCC-263, p. 3; Late Filed Exhibit No. 6; and Late Filed Exhibit No. 12. As a result, the adjusted DCF cost of equity is 11.0%.

6. Overall Rate of Return

[63] On a test year basis, projected to the mid-point of the upcoming rate year, the Company requested an overall rate of return of 9.45% reflecting a return on equity of 11.78%. After study and deliberation of all cost of capital issues presented in this proceeding, the Department finds that 8.91% is a fair rate of return. This return is calculated for gas-regulated operations only, using the approved capital structure and capital costs, as follows:

.ps 7.6

Class of Capital	Amount	% of Total	Cost	Weighted Cost
Short-Term Debt	\$ 18,107,000	3.87	4.72%	0.18%

Long-Term Debt	\$237,348,000	50.67	7.37%	3.73%
Total Debt	\$255,455,000	54.54		3.91%
Common Equity	\$212,943,000	45.46	11.00%	5.00%
Total Capitalization	\$468,398,000	100.00		8.91%

The Department finds that these rates, when applied to the rate base found reasonable for the Company, should produce operating income sufficient for Yankee to operate successfully and serve its ratepayers, maintain its financial integrity, and compensate investors for risks assumed.

H. PERFORMANCE-BASED RATE PLAN

[64-71] In this proceeding, the Company requested that the Department consider and approve a number of provisions that are typically considered in the context of a performance-based rate plan. Specifically, that the Department consider and approve an earnings sharing mechanism (ESM), a service quality plan (SQP) and a mechanism for limited rate changes (infrastructure expansion rate mechanism or IERM). These provisions may make sense in the context of an overall plan that provides significant incentives for a regulated company to cut its costs of doing business and to otherwise manage and operate its business prudently and efficiently. Normally these plans have provisions in them that limit the ability of a company to request rate changes for some set period of time.

Indeed, the Company's testimony on these provisions seems to imply that the provisions constitute the beginning of a transition to performance-based ratemaking and are part of a four-year plan, and that rates are expected to remain relatively fixed (except as allowed under the IERM) for some period of time. Beschler PFT, p. 4; Soderman PTF, pp. 2-7 and 14. In particular, the Company argues that sharing earnings through the ESM will provide incentives to the Company to find operating efficiencies and growth opportunities. Soderman PTF, pp. 2 and 6. Such an argument only makes sense if rates are largely fixed for some period of time. Otherwise, greater incentives are achieved under normal ratemaking where the Company retains 100% of all earnings between rate cases. The Company also argues that its request on these provisions is similar to that allowed the other LDCs in the state. Soderman PTF, pp. 3-5. However, the similar provisions allowed the other LDCs were in the context of performance-based rate plans. See, Decisions in Docket Nos. 99-04-18PH03 and 99-09-03PH02.

Outside the context of a performance-based rate plan, the Department is reluctant to layer on mechanisms and provisions to traditional cost of service regulation. The

Department has allowed these types of provisions in the past only as part of a performance-based rate plan. In this Decision, the Department has analyzed the Company's proposed specific provisions with the expectation that the Company will limit its requests for rate changes over the next four years to those changes allowed under the IERM as modified in this Decision. Given the magnitude and uniqueness to Yankee of the proposed IERM, it is discussed separate from the other proposed performance-based rate plan provisions.

1. Earnings Sharing Mechanism

Yankee proposed an earnings sharing mechanism (ESM) as a method for ratepayers to benefit from synergies from the NU Yankee merger. It is Yankee's belief that an equitable sharing of merger synergies provides an incentive to encourage utilities to pursue operating efficiencies and growth opportunities through mergers in the changing local gas distribution industry. Yankee believes the sharing of merger synergies recognizes that, due to the merger, its cost of service will be permanently lowered in the future. As such, both Yankee's ratepayers and shareholders should be given the opportunity to achieve these benefits. Yankee also believes that an ESM will provide it with a greater incentive to aggressively search for methods to increase revenues and lower costs. Soderman PFT, p. 2. Through its ESM, Yankee proposes that all earnings in excess of 100 basis points above the allowed ROE be shared 50% by ratepayers and 50% by shareholders. Soderman PFT, p. 4.

The ESM would be calculated annually for the twelve-months ended December 31 of each year. Yankee plans to report the results of this calculation through a compliance filing associated with this proceeding. Soderman PFT, p. 7. Yankee believes that the ESM will provide an incentive for Yankee management to find operating efficiencies and growth opportunities that are not a result of the merger on a going forward basis. Yankee also believes that the ESM provides a vehicle for it to share with its ratepayer's benefits of efficiencies and business improvements that will occur that are related and unrelated to the merger. Soderman PFT, pp. 5-7.

a. Positions of Parties and Intervenor

OCC states that Yankee's proposed ESM is poorly designed. It believes that neither Yankee's ESM nor a performance based ratemaking plan (PBR) mechanism can serve as an appropriate replacement for traditional cost of service (COS) regulation. Navarro PFT, p. 3. In establishing a PBR, OCC cautions that the baseline revenue requirement must not be set too high as it will yield false savings. It believes that the utility will try to inflate the initial baseline and try to build in generous escalation factors and minimize offsets such as those from increased productivity.

An example of this is setting the baseline without completely taking into account known reduced expenses resulting from events which preceded the PBR. Cost savings from a merger implemented under traditional COS regulation should not be attributed to a PBR implemented at a later date. Navarro PFT, p. 6.

OCC also asserts that choosing a progressive rather than a regressive sharing mechanism is critical to provide utility executives with the appropriate economic incentives to pursue all economically efficient cost savings. It characterizes a progressive sharing mechanism where cost savings distributed to shareholders should increase as the cost savings increase. In this way, ratepayers get a fair share of the savings while providing the strongest encouragement for the utility to pursue all savings that are possible. Economic theory states that by the law of increasing marginal costs, the last unit of savings is far more expensive for the utility to achieve than the first, so shareholders need a progressively increasing share to ensure the pursuit of as much cost savings as possible. An ESM designed such that it allows the utility to retain 100% of the first 100 basis points over earnings and a smaller fraction of additional savings is clearly regressive. The utility receives all the early, easily achieved savings, and a reduced share of savings from earnings exceeding the 100 basis points threshold. OCC asserts that such an ESM allows the utility to shoulder little risk, and provides a strong disincentive to pursue additional cost savings which have a higher marginal cost to obtain. Navarro PFT, pp. 6 and 7.

OCC believes that gas industry structure changes and Yankee's changes in corporate structure, due to the merger with NU, create strong reasons for not implementing its proposed ESM in the near term. It believes that Yankee's costs and the effects of the merger have not yet stabilized. The full effects of the merger's organizational, operational and financial restructuring will take more time to evolve and manifest themselves. Due to this, it is premature to allow Yankee to have its requested ESM. This is especially true since some eventual cost savings may be the inevitable longer-term results of the merger. In addition, OCC asserts that the natural gas industry is undergoing the same kind of regulatory and restructuring tumult that the electric industry has been experiencing with numerous Federal and state initiatives to restructure the natural gas industry. As an example of this, he cites the number of gas industry restructuring-related proceedings by the Department over a multi-year period. Further, Yankee's industrial customers and some commercial customers now have access to firm transportation, interruptible transportation, and competitive sources of gas supply. Thus, OCC reasons that both Yankee and those residential and commercial customers not yet exposed to competitive gas supply markets face continued transition costs, considerable uncertainties and further operational and financial changes. These are reasons for not implementing Yankee's ESM at the present time. Navarro PFT, pp. 9-11.

The AG believes that the Department should not adopt any PBR plan for Yankee at this time. It is too soon after its merger with NU for an accurate baseline revenue requirement to be determined, which is essential to an effective PBR plan. The AG asserts that the Department in the instant proceeding, has no accurate baseline revenue requirement for Yankee since the NU/Yankee merger will continue to reduce operating costs for the new entity. Brief, p. 15. The AG further asserts that even if this was an appropriate time to consider a PBR for Yankee, the proposed ESM is designed to allow it to retain 100% of the earnings in excess of its allowed ROE, and provides no benefit to the Company's ratepayers. Brief, p. 18.

The CIEC believes that Yankee's ESM is incongruent with Yankee's proposed IERM. CIEC asserts that Yankee looks to ratepayers to shoulder most, if not all, of the system expansion costs through the IERM. The Company, nonetheless, seeks to retain earnings for the first 100 basis points above its allowed ROE and then share, on an equal basis, all earnings in excess of that amount. CIEC believes that if the Department approves Yankee's IERM, all earnings in excess of Yankee's allowed ROE should be returned to ratepayers to achieve the appropriate balance between ratepayers and shareholders. Brief, p. 6.

b. Earnings Band Above Allowed ROE

In Yankee's proposal, sharing with customers would commence after the Company has earned more than 100 basis points above its allowed ROE. Yankee believes that its proposed ESM is consistent with Conn. Gen. Stat. 16-19(g). It interprets Section 16-19(g) as not prohibiting a regulated utility from earning more than its allowed ROE and permitting it to earn more than 100 basis points over its allowed return if it 'is directly beneficial to customers.' Yankee asserts that the proposed ESM will directly benefit customers by providing Yankee with a greater incentive to aggressively seek ways to increase revenues and lower costs. By design, Yankee set the proposed ESM trigger point at the same 100 basis points used in Section 16-19(g). This reflects Yankee's belief that the legislative intent was that some level of earnings above the authorized ROE can be acceptable and may provide reasonable and appropriate incentives. Response to Interrogatory GA-22.

OCC argues against the 100 basis point deadband questioning its legality under Section 16-19(g) based on the legislature's intent. OCC states that it is the only consumer protection statute in Title 16. The purpose of Section 16-19(g) is to provide ratepayers with protection from utilities' excess earnings. OCC believes that the legislative history shows that Section 16-19(g) was intended to serve as a counterbalance to Title 16. OCC quoted Senator Gary Hale who stated that '[w]e are saying in this bill that the consumer will now have even standing with the powerful utility companies.' OCC contends that approving an ESM where ratepayers are not

entitled to any part of the first 100 basis points of overearnings would take away the 'even standing' that the legislature created for ratepayers. OCC further asserts that the Department must recognize the inequity created in allowing a 100 basis point dead band in Yankee's ESM. If the Department allows a 100 basis point dead band, it will render the operation of 16-19(g) perfunctory and, therefore, meaningless to ratepayers. Brief, pp. 87-89.

The AG argues that the Department should reject Yankee's proposed ESM because it violates Conn. Gen. Stat. 16-19(g). It is the AG's belief that Yankee's proposal to retain the first 100 basis points of overearnings and 50% of all overearnings above that level plainly violates Conn. Gen. Stat. 16-19(g). It allocates future overearnings that must be the subject of a fair hearing on the need for an interim rate decrease. Brief, pp. 15-18.

The Department has taken a number of positions on whether a deadband should be present in an ESM based on the particular circumstances of each individual utility and industry. For example, the Decision dated February 2, 2000, in Docket No. 99-06-21, DPUC Investigation into Performance-Based Regulation for Electric Distribution Companies, states that:

The Department generally recommends that there either be no ROE dead band, or a relatively small one... . The economics of the sharing mechanism should work unimpeded in the absence of an ROE deadband because an EDC [Electric Distribution Company] would not retain the first one to two percent of cost savings. Further, by having a relatively small dead band or none at all, the opportunity to game PBR is reduced.

Decision, p. 14.

In addition, the Department approved a PBR plan for the United Illuminating Company (UI) where sharing began at UI's authorized ROE with no deadband. See, Decision dated December 31, 1996 in Docket No. 96-03-29, DPUC Financial and Operation Review of The United Illuminating Company. However, the Department did authorize a 100 basis point deadband above the allowed ROE in the Decision dated October 19, 2000 in Docket No. 00-01-11, Joint Application of Consolidated Edison, Inc. and Northeast Utilities for Approval of a Change of Control (ConEd/NU). The Department believes that the ConEd/NU Decision is an example of particular circumstances given that the Department ordered a rate reduction and the write-off of significant stranded costs. For LDC ESMs, the Department included a 100 basis point dead band in the Decision dated November 22, 2000 in Docket No. 99-04-18PH03. A deadband was not used in the Decision dated May 9, 2001 in Docket No. 99-09-03PH02.

The Department considered the arguments of the parties and intervenor, the evidentiary record and prior case experience as cited above. The Department found and still adheres to the following, as stated in Docket No. 99-09-03:

The Department recognizes that these past Decisions have cut both ways with regard to a deadband above the allowed ROE. However, this is consistent with a finding that earnings of up to 100 basis points above a previously allowed ROE represent neither a company entitlement nor a barrier against the use of such a deadband by the Department in an incentive ratemaking scheme. It is just such a finding that the Department believes is best supported by the record in this case. In reviewing any form of performance-based or incentive-based ratemaking, the Department must consider such a proposal in its entirety and its application to the specific company at hand.

Decision, pp. 14 and 15.

The Department believes that in some circumstances a wider deadband may be appropriate, but generally recommends that there either be no ROE deadband, or a relatively small one. The facts and circumstances of each case cited above differ, as do the various other components of their respective ESMs as approved by the Department. However, each achieves the balance of interests between ratepayers and shareholders that is the foundation of all Department considerations. Every proposal that is presented to the Department must be considered in its totality, bearing in mind the specific circumstances of each utility. As such, in the instant proceeding, the Department approves an ESM for the Company. In Yankee's particular circumstance, the IERM argues for a no deadband approach to allow for customers share of the ESM funds to flow to finance the capital projects of the IERM. The sharing of earnings between shareholders and ratepayers will commence with respect to earnings that exceed the allowed ROE, and no deadband will apply.

c. Earnings Sharing Percentage

Yankee proposed 50/50 earnings sharing between its shareholders and ratepayers. Soderman PFT, p. 4. Yankee's rationale for establishing an ESM with this sharing is based on weighting both the interests of shareholders and ratepayers equally and on the sharing percentages given to other utilities in recent Department Decisions. Yankee believes that ratepayers and shareholders should be provided the opportunity to share the earnings of the Company equally at 100 basis points above the allowed ROE. Response to Interrogatory GA-25.

The Department has taken various positions on ESM sharing percentages and steps given the individual circumstances of the specific utility. In Docket No. 99-04-18PH03, the Department approved an ESM that provides for a 50%-50% sharing of earnings at 100 basis points above Southern's allowed ROE between ratepayers and shareholders. See, Decision dated November 22, 2000, p. 17. In the Decision dated May 9, 2001, in Docket No. 99-09-03PH02, the Department approved an ESM with sharing of 75% to shareholders and 25% to ratepayers for the first 200 basis points of earnings above the allowed ROE. Earnings between 201 basis points and 600 basis points above the allowed ROE are shared 50% to shareholders and 50% to ratepayers. All earnings in excess of 600 basis points above the allowed ROE are shared 25% to shareholders and 75% to ratepayers. Decision, p. 16.

The Department analyzed the pros and cons of various ESM percentages, which center on progressive versus regressive mechanisms. OCC favors a progressive mechanism for reasons given above. Yankee stated that regressive versus progressive has no impact on its motivation to produce earnings for shareholders. He stated that '[s]o while one might think that if you have a higher percentage earlier on in the sharing mechanism, that you only do the easy stuff and forget the hard stuff. I don't believe that is a true reflection of the motivations and incentives to utility management.' Tr. 10/29/01, p. 2784. The Department finds that it must agree with the Company given its knowledge of Yankee's procedures and business practices.

The Department found in Docket No. 99-06-21, that a proportionate sharing mechanism is relatively easy to administer and may be less subject to gaming compared to other mechanisms. See, Decision dated February 2, 2000, p. 14. However, in the instant proceeding, the Department believes that other considerations weigh more heavily that makes a proportionate sharing mechanism undesirable. These considerations are the recent merger producing synergy savings and that ratepayers not support rates that lead to excessive earnings as well as the requested IERM. The Department believes that the IERM is an important element of the Company's Application and future business plan, which needs to be incorporated in a significant way into the ESM sharing percentages. Therefore, the Department approves a more progressive sharing mechanism, as compared to the Company's request. The Department approves the following sharing mechanism:

. For the year ending 2002, sharing at 75% shareholder and 25% ratepayers of the first 100 basis points over the allowed ROE with sharing of earnings at 50% shareholders and 50% ratepayers for all earnings in excess of the first 100 basis points.

. For the years ending 2003 and 2004, sharing at 75% shareholder and 25% ratepayers of the first 50 basis points over the allowed ROE with sharing of earnings at 50% shareholders and 50% ratepayers for all earnings in excess of the first 50 basis points.

. For the year ending 2005, sharing at 50% shareholders and 50% ratepayers starting at earnings in excess of the allowed ROE (Annual Variable Sharing).

The Department believes that increased ratepayer sharing of earnings in later years complement potential positive cash flows from IERM projects in these same later years. The Department believes that ratepayers funding these IERM projects, through their portion of sharing, should reap the increase in operating income that should be realized through the IERM projects. Therefore, the Department approves an Annual Variable Sharing mechanism that provides increased ratepayer funding in the beginning of the IERM and less when the cash flow of the projects are increasing.

The Department believes that the Annual Variable Sharing mechanism should provide a significant incentive for Yankee to achieve maximum synergy savings and finance system expansion through the IERM while limiting the potential for excess earnings. Although testimony in the instant proceeding recommended sharing mechanisms other than the one approved herein, expert opinion supporting a particular methodology does not bind the Department to a particular result (Connecticut Natural Gas Corporation v. PUCA, 183 Conn. 128, 143 (1981)). Pursuant to Conn. Gen. Stat. § 4-178, the Department may use its experience, technical competence, and specialized knowledge in the evaluation of evidence in contested cases.

d. Ratepayers Share Flowing to the IERM

Yankee's IERM is an aggressive 5-year system expansion program which will require Yankee to spend a significant amount of capital beginning in 2001 and continuing through 2005. Yankee proposes that the ratepayers share of the ESM be allocated to offset any rate increases resulting from the IERM. If there is a remaining balance for the ratepayer's share of the ESM, this amount would be 'banked' by Yankee to offset subsequent years increases in the IERM. Soderman PFT, pp. 7 and 8. The accounting for this would be a debit to an expense and a regulatory liability account would be credited for the ratepayer's share of the ESM that would flow to fund the IERM. Tr. 9/24/01, p. 126. Yankee would pay interest on the funds in this regulatory liability account at the rate of interest equal to their allowed rate of return. Tr. 9/24/01, p. 127. Yankee believes that the IERM will raise rates by approximately 2% to 3% but due to the ESM this cost for the system expansion will be mitigated to ratepayers. Tr. 9/24/01, pp. 100 and 101. The Department believes that

system expansion is good and that using earnings that flow through the ESM to fund the IERM will serve to lessen the impact on ratepayers. As discussed more fully in Section II.I. System Expansion below, the Department will require ratepayer funds from the ESM to be used to fund IERM projects prior to new charges being levied.

e. Customer Crediting Methodology

For the ratepayers' share of the ESM remaining after the financing of the IERM, the Department believes that the proper approach should be consistent with the way rates are designed such that shared earnings are credited to customers in proportion to Yankee's revenues. The Department believes that the allocation to firm sales and transportation customer classes should be consistent with the allocation of revenue requirements to these classes. Using a volumetric methodology within customer classes has the advantage of being fair, relatively easy to apply, easy to track and comprehensible to customers. The methodology is fair because it is based on class contributions and customer usage. Customers will receive benefits roughly equal to their contributions to revenues. The Department used this same methodology in the Decision dated November 22, 2000 in Docket No. 99-04-18PH03, and in the Decision dated May 9, 2001, in Docket No. 99-09-03PH02. The Company believes that transportation customers should share under the ESM just as they are expected to share the impact of Yankee's proposed rate increase and IERM. Response to Interrogatory GA-32.

As such, the methodology the Company is directed to use will return credits to firm sales and transportation customers under the earnings sharing mechanism. It will be based on each customer class' share of overall revenue requirements and by volumetric or customer use within its class. The Company will develop a per ccf credit by customer class by allocating the dollar amount that will be returned among the various customer classes consistent with each class' share of revenue requirement and dividing into the allocated dollar amount by the forecasted sales for each class for the credit period. As an example, assume Yankee should return through the ESM \$1,000,000 over the next two-month period. If there were two classes, (x) and (z), whose contribution to total revenue requirement is 60% and 40% respectively, CNG would allocate \$600,000 to class (x). If Yankee forecasts that class (x) will use 10,000 ccf of gas each month for two months, the per ccf credit to class (x's) customers would be \$30/ccf ($\$600,000 / (10,000 \text{ ccf} * 2 \text{ months})$). Since forecast sales will always differ from actual sales, Yankee will true up the discrepancy through an adjustment to the calculation for a subsequent period. Yankee will be responsible for tracking the amount of credits returned to customers to ensure that customers receive the full amount of shared earnings to which they are entitled. Firm sales and transportation customers both directly contribute toward Yankee meeting its revenue requirement. Due to this, the Department determines that both firm sales and transportation customers will be eligible for the credit. The

Department determines that customers will be credited using a line item on their individual bills since this will provide for better customer information.

f. Conclusion on Earnings Sharing Mechanism

Based on the above, the Department finds that the ESM should be calculated using a cost of capital calculation for the earned ROE consistent with the Department's Uniform System of Accounts. Any penalties which Yankee incurs will be recognized below the utility operating income line and will not reduce earnings for purposes of the above calculations. Any such calculated ROE amount above the allowed ROE will be shared between ratepayers and shareholders as specified above under an Annual Variable Sharing methodology.

2. Service Quality Plan

[72-74] The Company's proposed Service Quality Plan (SQP) measures were designed to ensure that the quality and reliability of service do not diminish as merger synergies are achieved. The SQP is based on feedback provided by customers through the Company's satisfaction survey and through focus groups. Responses to Interrogatories CA-12 and CA-30. The SQP measures do not differentiate among customer classes. Response to Interrogatory CA-16.

The Company's surveying efforts to elicit direct customer input as to what customers' value as SQP measures is extremely limited because the survey questions are not open-ended allowing customers to chose significant customer SQP components. Additionally, because the proposed objectives are limited, it leads Department staff to question if the benefits to be derived from the SQP are significant. Tr. 11/5/01, p. 2943. It also is not clear, nor does Company testimony delineate between on-going customer service improvements, improvements derived from the merger, and/or those due to the proposed SQP. The Company also has no plans to educate its customers regarding the SQP. Tr. 11/5/01, p. 2943. Most important, Yankee does not offer the Department a plan to review, monitor, and/or enforce its SQP.

OCC states that Yankee's SQP is not designed to protect customers against the deterioration of service. It does not include all appropriate performance measures, relies upon performance goals that are less than the average of historic performance levels, and includes penalties that are not sufficient to offset the financial benefit that the Company might enjoy by not achieving the performance goals. Brief, p. 121.

The AG states that Yankee's SQP should be rejected because the financial penalties proposed by the Company are not sufficient to protect the ratepayers' interests. Additionally, its proposal to include rewards as well as penalties is unnecessary, represents poor policy and is beyond the scope of a service quality control mechanism. Brief, pp. 19 and 20.

a. Billing Based on Actual Meter Reads

Yankee proposed to use billing based on actual meter reads as a SQP measure. The Company calculated its proposed SQP measure by comparing the annual number of bills that are based on actual meter reads occurring in calendar year 2000 to the total number of bills generated during that year. This calculation resulted in a 98.50% metric for the year. This is an increase over the billing based on actual meter reads of 97.90% in 1998. Beschler PFT, pp. 9 and 10.

The Department believes that the metric of 98.50% for billing based on actual meter reads is appropriate as a SQP measure. It is equal to or greater than the data collected during the time period of 1998 through 2000. Further, the Department believes that the proposed benchmark is reasonable, since it maintains a high target as a SQP measure. The Department believes that if the Company exceeds its SQP target, service will be improved to customers.

b. Customer Satisfaction

Yankee tracks customer satisfaction through monthly surveys. The surveys are sent by post card to all customers who call Yankee regarding their accounts. The survey results are analyzed and reported on a quarterly basis. The purpose is to find out how the customers were treated, how long it took to resolve their issues, and the customer s' feelings regarding the provision of and rates for service. In addition, a customer satisfaction benchmark survey is conducted every four years, which determines attributes that drive customer satisfaction. The last benchmark survey was conducted in 1998 and the next one is scheduled for 2002. Response to Interrogatory OCC-328. However, due to the fact that the benchmark survey is conducted every four years and not on an annual basis, the results may only be accurate in the first year it was conducted. It may not reflect accurately what customers consider quality customer service in the remaining three years. The Company testified that it would not use a survey as a component because the results are subjective. Tr. 11/5/01, p. 2939.

Based on the aforementioned, the Department finds that the SQP lacks a valuable service quality component necessary to gauge the quality of service rendered to its customers. The Department is aware that all Connecticut LDCs conduct customer satisfaction surveys. Further, Southern and CNG were ordered in the Decisions in Docket Nos. 99-04-18PH03 and 99-09-03PH02 to include a customer satisfaction survey as a component in their respective incentive rate plans. The Company's testimony did not reflect why its surveys lacked objectivity, what biases the surveys entailed, or the Department's requirements regarding the development of a customer satisfaction survey. The questions in the customer satisfaction benchmark surveys are not open-ended and do not directly reflect what customers' value as significant SQP components. The Company did not poll its customers to learn what SQP components they felt to be most important. The objectives proposed by the Company are limited and do not reflect a commitment to make significant improvements in service quality. Yankee did not propose a plan to monitor and enforce its SQP, nor to educate its customers and seek their feedback. The Company's testimony and exhibits are not clear as to whether customer service improvements are to arise from the execution of a satisfactory SQP or from the merger.

As stated above, the Department approved a customer satisfaction survey for CNG and Southern that established a baseline level of customer satisfaction and included goals and benchmarks. Yankee will be directed to follow that directive to develop and conduct a customer satisfaction survey as a SQP component. The Department believes the addition of an overall customer satisfaction survey as a SQP component to be proper. Implementing the survey and the Department Scorecard as additional SQP components would provide a more accurate picture regarding the quality of service rendered.

Finally, the Company's SQP does not include a component that measures the complaints filed with the Department. Response to Interrogatory CA-13. However, the Company is familiar with the types and number of complaints the Department receives by way of the Department's Annual Utility Scorecard. The Company should periodically examine the Department's complaint records during the year and its Annual Scorecard. This would allow Yankee to be better equipped to make positive changes to the delivery of customer service. It also could help reduce the number of complaints filed with the Department. Yankee reasoned that complaints received by the Department are subjective and can be influenced by factors that are beyond the Company's control. These include the price of gas, inability of customers to establish payment arrangements, and customers who have received shut-off notices. Responses to Interrogatories CA-33 and CA-13. However, Yankee testified that it does not object to the Department's Scorecard. Tr. 11/5/01, pp. 2939 and 2940.

The Department considers complaints filed with a regulatory authority to be a valid measure of customer service. The Department will direct Yankee to include such complaints as an additional component of Yankee's SQP. In the Decision in Docket No. 99-09-03PH02 -- Incentive Rate Plan, CNG was ordered to include complaints filed with the Department in its incentive rate plan. As established in the CNG proceeding, Yankee also will be required to include this component in its SQP. The benchmark would be to reduce the number of Yankee complaints filed with the Department by 5% annually.

c. Call Center Responsiveness

Yankee currently tracks Call Center Responsiveness or Average Speed of Answer (ASA). Response time is determined by Yankee's Automated Call Distribution System, which tracks and calculates the average number of seconds it takes for each call to be answered by a customer service representative. Response time statistics are recorded on half-hour intervals and are reported on a daily basis. Response to OCC-63. The Company's ASA includes only those calls answered by an employee and does not include abandoned calls. Response to Interrogatory CA-22. The ASA measure is based on a 12-month rolling average measurement before determining if a penalty is warranted. Yankee did not consider using a variable that provides a penalty for the number of times in which a variable 'X' exceeds a threshold in a given month, because of the proposed metrics coupled with Yankee's operations. A rolling average provides the Company the appropriate degree of flexibility to attain the SQP performance measures during the plan period. Response to Interrogatory CA-15.

The Department believes that a 12-month rolling average can hide those months in which the Company is operating below the established benchmark. If the SQP had been in place for calendar years 1999, 2000, and 2001 to date, the Department believes that the Company would have been penalized for not having an ASA equal to or below the proposed 45-second ASA benchmark. Response to Interrogatories CA-10 and CA-20. Yankee will be directed to reduce the proposed 45-second ASA average to 30 seconds in the first year and by 5% annually thereafter. Yankee also will be directed to develop a process for tracking abandoned calls.

d. Service Call Responsiveness

The Service Call Responsiveness component is based on utility service appointments being met within a two-hour window. Response to Interrogatory CA-12. Yankee proposed to meet 80% of the scheduled service calls within a two-hour window. However, the Company did not begin tracking this measure as an SQP component until calendar year 2000. If Yankee's proposed benchmark for Service Call Responsiveness had been in

place since 2000, Yankee would not have received any penalties because its performance has been within the proposed deadband. Though the Company has achieved this parameter since year 2000 and projects a 1.5% improvement per year for 2002 through 2004, the projected improvement percentages are minimal. Late Filed Exhibit No. 113. The Company did not provide a response when asked if the projected minimal improvements are significant considering there are no plans to educate customers regarding the SQP. Tr. 11/5/01, pp. 2942 and 2943. The Company's year-to-date average for Service Call Responsiveness is 84.40%. Response to Interrogatory CA-20. Yankee will be directed to establish a Service Call Responsiveness benchmark of 85% for year 2002 and a 1.5% performance increase annually thereafter.

e. Suspected Gas Leak Call Responsiveness

One service quality measure proposed by the Company is Leak Response Time. That is the elapsed time from when a report of a possible gas leak (such as a gas odor call) is received by the Company until a Company person has arrived at the scene who is competent and qualified to evaluate the situation and take necessary actions to protect the public safety. As a prompt response to suspected gas leaks is arguably the most important public safety task of any gas utility, this service quality measure is designed to ensure that safety will continue to receive the highest priority.

The Company states that the standard for timely response is within 30 minutes of the time the leak report is received during normal business hours, and within 45 minutes outside of normal business hours. Beschler PFT, p. 8. This standard is consistent with current Department guideline limits for response during normal and off-hours. Yankee proposed to establish an annual benchmark of 94.5% of the responses within guidelines during normal business hours, and 96.5% during off-hours. A deadband for normal hours response times is proposed from 93.6% to 95.4%, and 95.5% to 97.5% for outside normal hours. Soderman PFT, p. 16.

The percentage of calls responded to within the Department guidelines during normal business hours and outside normal business hours since 1998 are:

Year	Normal Business Hours	Outside Normal Business Hours
1998	82%	89%
1999	83%	89%
2000	84%	91%

Beschler PFT, p. 8.

The Company states that the proposed 2002 benchmarks of 94.5% and 96.5% represent a significant improvement in responses to gas leak calls over year 2000 actual data for normal business and outside of normal business hours. The Company also stated that it recently implemented scheduling changes to more accurately match the volume of calls and related peak traffic times. This resulted in significant improvement in the response rate for year-to-date 2001 in both categories. The proposed benchmarks for 2002 reflect this improvement and represent the Company's continued commitment to meet the Department's guidelines in this area. Beschler PFT, p. 8. The Department is satisfied with the leak response time targets that Yankee has chosen, and fully expects that the Company will exceed this benchmark.

It should be noted that in addition to trying to ensure continued quality service in this area, the Department is also interested in improving this important safety function. While the Company is not achieving the guidelines 100% of the time, the benchmarks set here should be viewed as part of a progression from the previous status toward the ideal of 100% compliance. The current benchmarks for the leak response targets have been set at a reasonable level and the Department believes that the Company can achieve them based on its most recent performance.

Through its Gas Pipeline Safety Unit (GPSU), the Department is currently monitoring gas-leak responsiveness based on monthly filings made by the Company. The Department will continue to use these responses to monitor progress on an on-going basis. Additionally, as part of the Company's Annual Compliance Filing for the SQP, the Department will require a report of the monthly data for the prior 12 months, including the 12-month average. Penalties will be assessed as the Company has proposed if the benchmark is not met for any month out of the 12-month period, or if the average for the 12-month period fails to meet the specified benchmark.

f. Third Party Damage

The third party damage performance measure relates to the ratio of the number of times the Company's gas facilities are damaged by third parties (i.e., excavators not working for Yankee) compared to the number of times that the Company marks the location of its facilities pursuant to an excavation notice. Third party damage is one of the two major causes of damage to gas pipelines in Connecticut. See, Decision dated December 20, 1995, in Docket No. 95-03- 31, DPUC 9th Annual Report on the Condition of Gas Public Service Companies' Underground Facilities, p. 7. Therefore, measuring results of attempts to minimize these damage incidents is appropriate, and should provide a good safety measurement for the Company's operations.

The Company proposes a benchmark for third party damage of 3.52 incidents per 1,000 mark-outs with a deadband ranging from 3.17 to 3.87. The deadband for maximum rewards and penalties has been set slightly wider for this metric than for other metrics because of a new mapping system that has just begun to be used by the Call Before You Dig program. This new mapping system may cause the statistics to appear to worsen, when in fact the change is due to a change in methodology. Soderman PFT, p. 16. The data submitted by Yankee shows the following:

YEAR	INCIDENTS PER 1,000 MARK-OUTS
1998	5.332
1999	5.425
2000	3.899

Beschler PFT, p. 5.

The Company states that as shown above, the number of incidents per 1,000 mark-outs in the year 2000 has improved significantly. A benchmark of 3.52 represents a further 5% improvement over the number of incidents in the year 2000. The Company also testified that the significant improvement from 1999 to 2000 was due to Yankee's focus on correcting inaccurate facility records and errors by Company mark-out personnel. Further, the Company states that the year-to-year improvement might not be sustainable now that a new baseline has been established. The Company believes that a new mapping system currently being implemented by Call Before You Dig (CBYD) may decrease the number of requests it receives. Beschler PFT, pp. 5 and 6.

The Department is satisfied with the target proposed by the Company. However, the Department expects to see significant improvements in this area without regard to performance measures. Third party damage is an area of public safety to which attention must be paid by the Company. The Department particularly expects to see great improvement where the Company records were accurate but where its employees still failed to correctly locate the facility.

To monitor performance in this area, the Department will require the Company to file annually the most recent 12-month data plus the previous 12-month period, the monthly number of damage incidents, the number of excavation notices, and the resulting ratio. In addition, the Company will file this data monthly with the GPSU that it will review as part of its routine review of the safety operations of the Company. The Department notes that damage from third parties occurs primarily during

the construction season, and as such, the likelihood of incidents is seasonal as well. Therefore, penalties for this measure will be assessed on an annual basis only, based on the average annual benchmark performance.

g. Penalties

In its Application, the Company proposes a symmetrical reward/penalty mechanism for the SQP that provides maximum rewards/penalties of \$5,000 in year one, \$10,000 in year two, \$15,000 in year three and \$20,000 in year four. Soderman PFT, p. 14. The Company further proposes that the rewards/penalties not be applied until after a dead band around each benchmark has been breached and, even then, only proportionally until the maximum amount is reached. Soderman PFT, p. 15. The Company also proposes that its performance with regard to its SQP be monitored annually. Beschler PFT, p. 3.

The Department reviewed the Company's proposed reward/penalty mechanism and has a number of concerns. Using an arithmetic average to calculate performance under the SQP could conceal poor performance in the short term. Even when the annual performance would meet the benchmark, monthly response time could be substandard. The Department finds this unsatisfactory. Ratepayers should be protected from poor customer service at all times, not just on average. Southern and CNG were both directed, for the purpose of determining penalties, to consider themselves subject to a penalty for each month over four months that the respective company fails to meet its respective benchmark. See, Decisions in Docket Nos. 99-04-18PH03 and 99-09-03PH02. Therefore, to calculate an annual performance relative to a benchmark, the Department will consider Yankee to have failed to perform satisfactorily if for any five months out of 12 months a measure's performance is below its benchmark. This modification to the determination as to whether a benchmark has been met does not apply to Third Party Damage (annual measure only) or Suspected Gas Leak Call Responsiveness (monthly and annual) as specifically noted above in the sections discussing these measures.

The Department agrees with the Company that any penalty for failing to perform according to the SQP benchmarks should be charged solely to shareholders by charging it below-the-line and crediting it to ratepayers' bills. With regard to the proposed magnitude of the penalty to be assessed and the reward aspect of the mechanism, the Department finds that the penalty should be significantly greater, in line with the level in place for Southern and CNG, and that the reward aspect is inappropriate. The purpose of establishing an SQP, including benchmarks, is to prevent the Company from sacrificing service quality in its pursuit of cost savings. The focus is not to motivate improvements. As such, an SQP need not include rewards. The amount of the penalty to be charged below-the-line charge will be \$100,000 for every service

quality measure for which the performance is below the measure's benchmark. The Department establishes the \$100,000 penalty so that there is a consistency across the LDCs in this regard. In addition, Yankee will address any service quality measure that failed to meet its benchmark, and file a report that includes a remedial plan to bring the performance measure up to the benchmark.

3. Compliance Filing

Yankee proposes that the ESM will be calculated on an annual basis for the 12-months ended December 31 of each year. After the calculation has been performed, Yankee will report the results to the Department through a compliance filing under the docket number of the instant proceeding. Soderman PFT, p. 7. Yankee proposes that its compliance filing use a cost of capital calculation showing a ROE and the resulting sharing with ratepayers. Yankee will also provide an income statement, rate base and capital structure information. Response to Interrogatory GA-35. The Department approves the ESM with the addition of the following information:

1. An analysis of how actual savings compare to Company savings estimates presented in this proceeding and in the Decision dated December 20, 1999 in Docket No. 99-08-02.

2. An evaluation of customer service quality through trends and analyses of service quality before, during and expected through the remaining IRP period.

3. Investigation into past or potential problems or benefits.

4. The extent of new customer additions and the status of any new customer or marketing efforts.

5. Current and expected capitalization specifically changes in Yankee's debt to equity ratio, total capitalization and rate base per customer.

6. Individual IERM projects and funds expensed for each.

I. SYSTEM EXPANSION

[75-80] The Company proposes to embark on an aggressive five-year system expansion program consistent with the commitments made in the NU/Yankee merger proceeding. The multi-year system expansion plan would encompass towns and locations that are currently not served. The Company emphasizes that this is a total change in its expansion plans from the past where it expanded by attempting to gain customers along existing service mains. Ferrantino PFT, pp. 2 and 3. Yankee's expansion plan attempts to accomplish four goals: 1) improve reliability of the Company's delivery system; 2) provide growth in Yankee's distribution system; 3) provide greater fuel diversity and increased availability of gas to Connecticut's consumers; and 4) support economic development initiatives in Yankee's service territory. Ferrantino PFT, p. 4.

Under the plan, Yankee proposes to spend a significant amount of capital beginning in 2001 and continuing through 2005. To assure recovery of its capital expenditures, the Company proposed a rate mechanism to allow it to proceed with the expansion. According to Yankee, the proposed Infrastructure Expansion Rate Mechanism (IERM) would provide it with the opportunity to increase rates in future years as system expansion projects are completed and included in plant-in-service, without filing a new full rate case. To effect the IERM when necessary, the Company would seek a limited reopening of the current rate proceeding to include the capital expenditures for these projects and the LNG facility in rates.

Yankee proposes to file information on the IERM on October 1 of each year (filing year), including a forecast of plant-in-service for the subject IERM rate year (e.g., 2003). Yankee would also file an estimate of the customer portion of the ESM for the filing year (e.g., 2002). Yankee stated that it would provide a calculation of the necessary return of and on the new plant-in-service, offset by any ESM earnings that would need to be returned to customers. The net revenue requirements for the incremental infrastructure project expenditures would serve as the basis for the IERM rate increase to be implemented on January 1 of each rate year (e.g., 2003). Soderman PFT, pp. 8 and 11. Specifically, the Company expects to submit schedules that calculate the revenue requirement for the system expansion expenditures that are projected to be in-service during the IERM rate year. It will include a summary of the revenue requirement and the beginning and ending rate base balances to support the return on rate base. Response to Interrogatory GA-54. The Company proposes to increase future base rates on an annual basis for those system expansion capital expenditures that would normally be added to rate base in years 2003-2005. The impact on future rates of including these capital expenditures would result in the following increases: \$7.8 million in 2003; \$12.7 million in 2004; and \$10.7 million in 2005. Soderman PFT, p. 10.

The Company believes that the IERM is similar to the general rate making process. In a rate case, the Company proposes a rate level for the rate year that is premised

on a rate base that contains capital additions to the system. Yankee states that the IERM is different from the generally accepted rate making process because it does not consider the entire cost-of-service for the projects within the expansion program. Since the entire cost-of-service is not included in these projects, there is no review of O&M expenses associated with the IERM. However the calculations of the net present value (NPV) and internal rate of return (IRR) and related calculations do include depreciation and expenses related to taxes. Tr. 9/28/01, pp. 368 and 369. The Company expects that O&M associated with the IERM projects would be collected through the general body of ratepayers under the general rate structure. Tr. 9/28/01, p. 373. It did not include in the IERM the \$2.2 million worth of O&M, overhead, and other expenses associated with the expansion program. Late Filed Exhibit No. 17.

The Company proposes to include the ratepayer's share of the ESM in the IERM to offset the costs associated with the expansion program. Without the ESM being included in the IERM, the Company believes that the capital budget and associated rates would increase to cover the costs associated with the expansion program. Further, the Company is not willing to guarantee the dollar figure on the ESM contribution to the IERM. Tr. 9/28/01, pp. 377-381. It needs the IERM to recuperate costs associated with the expansion program. Yankee's need to recuperate the costs associated with the IERM in an expedited manner does not stem from a financial problem with the parent company, NU. Rather, the Company states the problem is that when NU makes an investment in capital it expects a fair return for the money that NU is lending to Yankee for its capital expansion program. The Company states that if the returns were not there, NU would not lend the money for the expansion programs to Yankee. The Company indicates that there is a period of time where the costs associated with these projects will exceed the incremental revenues that the projects will generate. Tr. 9/28/01, pp. 388-408.

The Company used an economic model that was similar to the hurdle rate [FN15] to analyze the projects contained in its IERM. In this model, the Company projected the number and types of customers and related volumes of gas it expects each customer to use during the first six years of each expansion project. For each project, the Company calculated a net present value (NPV), return on capital (ROC), internal rate of return (IRR), total revenue, net revenue, margin and net margin at a specific point in time. The Company states that a positive NPV and IRR means that the value of the project over the analysis period is positive. Therefore, cash flows resulting from the project are greater than cash flows needed to construct the project. A negative NPV and IRR means that the revenue is less than the capital expenditures used to build the project. The Company states that the economic model used to analyze the expansion projects is a cash flow model that compares the revenue related to the projects to the expenditures related to pipes and meters being placed in service. Tr. 10/1/01, pp. 637-648. In evaluating the different projects, the Company considered various time periods to determine when a positive rate of return

was achieved. Id., p. 682.

1. Construction Program

Many of the proposed projects correspond with reconstruction of roadways along the anticipated route. The Company states that this is efficient and would save customers money associated with repaving costs. Tr. 9/28/01, pp. 388-408. The Company contends that the total capital budget for the IERM, excluding the construction costs associated with the LNG facility, are expected to approximate \$190 million. The Company believes that if the Department were to approve the \$190 million, it would be authorized to spend up to that amount. The Company is not willing to stop the expansion projects at the end of the rate year, and to evaluate the projects that have been completed before moving on to the rest of the expansion projects. Tr. 9/28/01, pp. 408-410. The Company indicated that it would agree if the Department approved a recovery mechanism similar to the IERM but removed the costs associated with the LNG facility from the IERM. The Company stated that it is willing to look at a phase type arrangement related to the cost recovery of the LNG in place of the IERM. 9/28/01, pp. 430 and 431.

The Company's proposed expansion program contains 32 projects that are scheduled to be completed during the next five years. The initial phase of the plan encompasses 12 projects that are proposed to commence in the years 2001 and 2002. The Company stated that some of these projects are infrastructure extensions within towns currently served by Yankee and others are projects within towns that have low main penetration. [FN16] Ferrantino PFT, p. 7.

2. Positions of Parties and Intervenors

a. Office of Consumer Counsel

OCC states that while it is in favor of prudent system expansion by Yankee, it opposes the IERM and recommends that the Department deny it. Prudent utility system expansion must contain projects that are financially viable for stockholders and ratepayers. OCC believes that the IERM is an attempt to avoid showing prudence in a full rate case presentation. If a project is not financially viable, the utility should collect a Contribution in Aid of Construction (CIAC) from the developer or customer. The CIAC would make up the cost difference between the anticipated costs and the costs that are necessary to meet the hurdle rate. The benefit of collecting the CIAC from the customer is that the ratepayer is not forced to subsidize a project that is financially unprofitable. OCC states that Yankee decided in the past

that CIAC should only be collected on service extensions and meters. This practice not only requires 'other' ratepayers to subsidize the Yankee ratepayers who benefit from the project under the IERM, it shifts additional financial risks attendant to these projects from Yankee to its ratepayers. OCC argues that Yankee must begin to collect appropriate amounts of CIAC from its customers if it expects approval of these optional projects in rate cases. Brief, pp. 111 and 112.

OCC states that investors have historically absorbed the costs necessary to increase market share and improve existing system infrastructure between rate cases. Yankee's proposal forces consumers to prematurely fund or subsidize investments that shareholders are not willing to fund. OCC argues that the Department should continue to use the traditional rate making process for expansion projects. This allows all of the involved parties to thoroughly review and analyze the entire financial and operational situation of the utility. According to OCC, the IERM includes significant capital additions which produce earned returns lower than the expected earned returns on existing Yankee plant. This requires revenues from ratepayers who are not using the plant additions. Cotton PFT, pp. 8 and 9. Further, OCC believes that any recuperation method set up for the LNG facility should be separate from the expansion program. Including the LNG facility in the IERM would leave ratepayers vulnerable to cost increases that relate to changes in the design or construction costs. Brief, pp. 111 and 112.

OCC believes that only 5 of the committed 15 projects cross over and provide a positive cumulative net benefit by 2010. This is where the project's cumulative margin exceeds the cumulative return on investment, as well as related operating and maintenance expenses. Brief, p. 34. Yankee only has a total of 267 commitments for service in the areas of the 14 projects for 2001. The current commitments will not produce sufficient revenue margin to cover the added costs of the system expansion. Moreover, OCC believes that Yankee will need to significantly increase the number of customers for the projects than have been estimated to justify the projects. Brief, p. 35. OCC states that even with the IERM projects that do produce revenues, the growth in revenues is excluded in the IERM proposal and is not to be flowed through to the benefit of the ratepayers. OCC argues that the IERM is one-sided and only increased expenses are flowed through to the ratepayers. Brief, p. 108.

OCC states that the response to Interrogatory GA-7 points out that under existing hurdle methodology several of the Company's projects have positive NPVs and above hurdle IRRs. These projects should be done without an IERM. The Company should do these projects, which easily pass its hurdle test on their own merit, between rate cases with no guarantees. The risk of their completion, their need and their estimated value should continue to be borne by the shareholders. These are the proper risk takers because their risk is being compensated in cost of capital of charges to ratepayers. OCC asserts that Yankee does not need Department approval to

build any project between rate cases. This is a misconception of the IERM proposal. Brief, pp. 104 and 105.

OCC also points out that many of the IERM projects have a negative NPV and several of the largest projects had the highest negative NPV. OCC believes that may be one reason that the Company deemed it an IERM project and why it is proposed to be approved between rate cases. If it were included in the rate year of a fully litigated rate case, OCC believes that it would be denied as financially imprudent. OCC says it is a travesty to force ratepayers to subsidize IERM projects with substantially negative NPVs that are of benefit only to a specific business or entity. OCC states that either the Company must include a proper assessment of incremental revenues in support of these projects or it must require a CIAC from the developer or entity benefiting from the project. Brief, p. 110.

OCC contends that Yankee seemingly acknowledges that its IERM proposal alone represents an 8% base rate increase over the next three years when it interjects a regulatory offset to the IERM. Instead of directly returning or refunding to ratepayers any ESM earnings that would accrue to its customers, Yankee proposes to offset the IERM rate increase by ratepayers' share of ESM over-earning. Thus, even when the customers are entitled to a refund, they will never receive a rate reduction because the ratepayers' share of the ESM is overwhelmed by the Company's accelerated IERM annual increases. OCC states that even in the potential rare occasion that ratepayers' share of the ESM exceeds the IERM rate increase, Yankee has requested that it be allowed to bank ratepayers' excess ESM to offset future IERM rate increases. The IERM, as designed, eliminates the ratepayer benefits provided for in the NU/Yankee Merger and the Department should reject outright for that reason. The IERM annual increases will be a tremendous and unfair burden to Yankee ratepayers. OCC recommends that the Department totally reject the IERM scheme and the ESM offset feature in total. Brief, pp. 107 and 108.

In conclusion, OCC states that it is in favor of prudent system expansion by any utility in Connecticut. However, it is opposed to the IERM and recommends its denial. Prudent utility system expansion must contain projects that are financially viable for the stockholders and the ratepayers. OCC believes that the IERM seeks to avoid a showing of prudence in a full rate case presentation and instead seeks a limited proceeding where the Department only can look at ways in which rates will be increased. If a project is not financially viable, it is up to the utility to collect a CIAC from the developer or customer to make up the cost difference so that the rest of the system's ratepayers are not forced to subsidize a financially undesirable project. The IERM violates this principle. The current regulatory framework has not shown itself to be unworkable. To the contrary, the current regulatory framework has stood the test of time. Brief, p. 12. OCC recommends that the Department use the following guidelines for projects included in any system

expansion.

1. Projects must meet the existing hurdle rate calculation or provide a positive NPV over a 30-year period using the Company's after tax rate of return.

2. Projects must provide a cumulative financial benefit that covers return of and on the Company's investment and O&M expenses within ten years of construction.

3. The Company must provide detailed information regarding the necessity of reliability improvements realized by projects that do not meet criteria 1 and 2.

4. The Company must provide detailed economic development, environmental, and energy policy benefits that will be realized and warrant going forward with projects that have negative NPV or fail to cross over and provide cumulative financial benefits the first ten years.

5. The Department retains the right to disallow expansion projects that the Company stated would become profitable and later do not.

Brief, pp. 102 and 103.

b. Attorney General

The AG states that the IERM represents a departure from the traditional regulatory process where a utility makes a capital addition and then seeks to include the capital addition in rate base at the next rate proceeding. It recommends that the Department reject Yankee's IERM proposal as bad regulatory policy, because it unfairly burdens Yankee's ratepayers with an uneconomic expansion program. The Company's proposal is also bad policy because it is one-sided. Specifically, the IERM increases rate base for all new capital additions while ignoring traditional rate case adjustments that would reduce rate base and revenue requirements. Under the Company's proposal, Yankee would automatically raise its rates to reflect capital additions without any consideration of mitigating factors such as reductions in cost of capital, depreciation, tax adjustments, increased sales volumes and productivity improvements. It is plainly unfair to burden ratepayers with automatic pass throughs for capital additions without a comprehensive rate case evaluation of all elements of the Company's financial position that might mitigate the need for a

rate increase. The Department should not abandon the traditional rate process to evaluate the inclusion of additional plant in ratebase. Brief, p. 6.

The AG believes that the Company's IERM proposal unfairly shifts the risk of poorly planned or uneconomic expansion from shareholders to ratepayers where the Company's proposed expansion projects will not be subject to a hurdle rate analysis. The evidence plainly shows that the Company's proposed infrastructure expansion projects are clearly uneconomical and will burden Yankee's existing customers with the costs of serving Yankee's proposed new customers for years to come. According to the Company's best estimates, only 5 of the 19 proposed expansion projects will generate sufficient margins to exceed the Company's revenue requirements within the next 10 years. See, Late Filed Exhibit No. 30. The remaining 14 projects will remain unprofitable well beyond the ten year analysis. In fact, eight of those projects show internal rates of return ('IRR ') that are cumulatively negative for the next 30 years. Late Filed Exhibit No. 30; Response to Interrogatory GA-7, RV-01. AG states that Yankee specifically acknowledged that it seeks an exception from the traditional regulatory process because of 'the very common financial criteria that people don't invest money if they are not going to get their money back.' It is patently unfair to have Yankee's ratepayers fully subsidize these uneconomic expansion programs especially when its own shareholders find this risk unreasonable. Brief, p. 7.

The AG argues that the Company's proposal is even more unfair in its treatment of the additional revenues generated by the new plant. Under Yankee's proposal, ratepayers will be forced to bear all of the costs associated with the infrastructure expansion without receiving any offset from the additional revenues generated from sales to new customers. Instead, the Company proposes that these revenues flow directly into its operating income where they will be allocated under the Company's proposed ESM. As a result, the Company will retain the first 100 basis points, and split the earnings in excess of that amount 50/50 with ratepayers. See, Morris PFT, p. 6. Worse still, under the Company's proposal, ratepayers will never see their share of the revenues because the Company will simply 'bank' the ratepayers share of overearnings to pay for even more uneconomic infrastructure expansion in the future. See, Soderman PFT, p. 7. Thus, the Company's proposal unfairly treats all of the costs associated with the infrastructure expansion as the responsibility of the ratepayers while retaining 100% of the additional revenues generated by that ratepayer financed infrastructure for its shareholders. Brief, pp. 7 and 8.

Based on the aforementioned, the AG asserts that the proposed IERM represents bad regulatory policy because it eliminates the traditional regulatory review associated with infrastructure expansion. AG states that its recommendation concerning Yankee's appropriate ROE assumes the Department's rejection of the proposed IERM and ESM.

Should the Department approve any portion of the IERM or the proposed ESM, which it should not, the Company's operating risk would be lowered dramatically, thereby lowering the Company's appropriate ROE. Brief, pp. 5-6.

c. Connecticut Industrial Energy Consumers

CIEC states that while it generally supports the expansion of Yankee's system, ratepayers should not be forced to exclusively shoulder the costs of such expansion under the IERM. It believes that Yankee's proposed IERM places the full risk of system expansion on existing customers. No clear benefit exists for current customers to expand the Yankee system. Conversely, Yankee's shareholders stand to benefit considerably from the addition of customers without sharing in the risk associated with the expansion. CIEC agrees with OCC that 'Yankee's proposal poses a ...significant change in regulatory policy in that it forces consumers to prematurely fund or subsidize investments that the company's shareholders apparently see as not reasonable to fund.' See, Cotton PFT, p. 8. CIEC Brief, p. 3.

The CIEC argues that the inequity of the IERM is exacerbated by the lack of Department review of the system expansion program funded by the IERM. Under the proposed IERM, Yankee would be permitted to increase its rates annually in 2003 through 2005 without the regulatory review associated with a base rate proceeding. While certain exceptions to the rate case process exist that allow for direct collection of certain expenses, such as purchased gas costs, the Company's proposal is not akin to those limited exceptions. Rather, the Company's proposal extends for several years, involves significant capital additions, requires ratepayers to pay for plant additions that they themselves will not 'use,' and creates both rate base and income effects. Brief, p. 4.

CIEC believes that the Company's proposed IERM is myopic in focus, looking only at the increase in certain rate base elements, while ignoring other traditional rate case elements that would reduce revenue requirements and offset possible increases in rates. For example, the Company does not propose to offset its proposed rate base expense with any revenue produced by the projects in its System Expansion Program. As OCC testified, '[t]he regulatory process becomes much more reasonable when it reviews all of the items of cost, revenues, and service rather than just the selected rate base items included in the Company's IERM proposal that appear to increase costs.' See, Cotton PFT, p. 9. The proposed IERM process fails to incorporate countervailing factors that may mitigate costs associated with proposed capital additions. Brief, p. 4.

Department precedent recognizes the danger associated with surcharge mechanisms,

such as that proposed by Yankee. Approximately one year ago, the Department rejected a similar infrastructure surcharge proposed for water utilities. See, Decision dated September 6, 2001 in Docket No. 99-01-02, Infrastructure Replacement Adjustment Surcharge for Water Companies; 203 P.U.R.4th 566. In that case, the proposed surcharge would have covered the fixed cost, including depreciation expense, associated with replacement of aging water distribution system facilities. The Department concluded that legislative action would be required prior to the implementation of such a surcharge, stating that '[a]t a minimum, the Legislature must find that infrastructure replacement is an immediate problem requiring immediate action.' See, Decision p. 8. Similarly, Yankee has failed to demonstrate that the public need and economic and environmental considerations are so imperative as to require abandoning the regulatory review process. Brief, pp. 4 and 5.

CIEC asserts that the Department should reject Yankee's proposed IERM to be consistent with its Decision on the surcharge mechanism proposed for water utilities. While the goals of system expansion such as economic development, inter-fuel competition and environmental considerations are laudable, the Company has not demonstrated adequate need to abandon the normal regulatory process in favor of the limited review contemplated by the proposed IERM. The proposed IERM improperly shifts the risk of the system expansion to ratepayers, with inadequate safeguards to ensure that their rates remain 'just and reasonable.' If system expansion is as essential as Yankee portrays, then Yankee's shareholders should certainly be more than willing to invest in these projects. If system expansion fails to entice investors, ratepayers should not be forced to bankroll these projects absent the Department's review and full consideration of all relevant factors under the established base rate process. Brief, p. 5.

CIEC states that Yankee proposes that all earnings in excess of 100 basis points above its allowed Return on Equity ('ROE') be shared on a 50-50 basis between customers and shareholders. Also, Yankee contends that this is an appropriate mechanism with which to recognize the 'value that investors made possible by virtue of the NU-Yankee merger.' CIEC contends that the 'synergies' allegedly provide incentives for Yankee to maximize cost reductions and pursue increased revenues in the future. See, Morris PFT, pp. 6 and 7. The paradox of Yankee's proposal is that, while the Company looks to ratepayers to shoulder most, if not all, of the system expansion costs, it nonetheless seeks to retain earnings for the first 100 basis points above its allowed ROE and then share, on an equal basis, all earnings in excess of that amount. The Yankee proposals are incongruent and fail to achieve 'the balance of interests between ratepayers and shareholders that is the underpinning of all Department considerations.' See, DPUC Review of the Southern Connecticut Gas Company's Rate and Charges -- III, 2000 Conn. PUC LEXIS 394, *35 (Nov. 22, 2000). CIEC believes that the Department should not approve Yankee's proposed IERM but if it does, all earnings in excess of the Company's allowed ROE must be returned to ratepayers to achieve the appropriate balance between ratepayers and shareholders.

Brief, p. 6.

3. Discussion

The Department believes that an IERM could be beneficial to the ratepayers in several ways. First the IERM reduces the need for the Company to come in for a complete rate case to recoup the costs associated with its expansion program. The Department believes that an IERM could be less administratively burdensome than the normal rate making method, and could potentially reduce costs associated with presenting full rate cases. However the Department believes that the Company's proposed IERM needs to be modified to share system expansion risk between ratepayers and shareholders.

As proposed by the Company, the IERM would transfer the risk associated with capital expenditures from the shareholder to the ratepayer between rate cases. Under a normal ratemaking method, the shareholder takes the risk associated with a capital expense, and then during the next general rate case the Company proposes to roll that expense into rate base. The Department considers that the risk associated with each project is greater than normal.

The Company has not included O&M and other related overhead expenses in the IERM calculations for the NPV and IRR. Further, the Department believes the Company has created an analysis that manipulates the analysis period and front loads customers into the customer analysis who are not expected to receive service during that year. Moreover, the analysis performed by the Company on the 32 proposed projects showed that less than 50% of the projects had a positive NPV and IRR. The Department reviewed all 32 proposed projects listed and analyzed in the response to Interrogatory GA-7 and had similar concerns with many of the projects. Illustrative of these concerns are the specific ones noted below for the Suffield Business District Project and Project Q.

The Department's review of the Suffield Project shows inconsistencies occur in the Company's analysis. First the Company shows an interruptible customer receiving service in year three of the analysis, but no future consumption in years four, five, and six. Response to Interrogatory GA-07. Due to the fact that the model only had six years of data, the Company put all potential remaining customers for the remaining 24 years of the evaluation in year six. This skewed the results. The Department believes the analysis should demonstrate the actual contracts with developers with a commitment or at least a development plan to build a housing development. The Company depended on the information obtained from the town's planning and zoning commissions to project its customer growth and to decide whether

to initiate a particular project.

The Department's review of Project Q determined the following. First the interruptible customer represents 50% of the consumption in the year the project is built. The interruptible customer happens to be one of the first customers to connect to the system. An 8-inch plastic pipe at 99 psi, 1,000 feet long, has a capacity of 2230 MCFH while a 6-inch plastic pipe using the same pressure and length of pipe has a capacity of 1099 MCFH. Late Field Exhibit No. 130. Based on the estimated consumption in the thirtieth year the interruptible customer represents approximately 40% of the gas consumption. As an interruptible customer uses the excess capacity that is not being used by firm ratepayers, the Company should have enough capacity to serve its expected firm sales customers. The Department believes that the Company has installed and sized the main to specifically acquire the interruptible customer shown in the analysis for Project Q. Further, the Company has shown in its map that the interruptible customer is at the end of the main. In this case, the Department believes that since the cost, NPV, and IRR is such a large negative dollar amount, the Company should take full risk of this project under the interruptible line extension policy (ILEP).

The Department believes that several criteria are important to apply to projects to be included in the IERM. First the IRR that the Company calculates for each project will include the total cost of a project, including capital costs and any costs that the Company currently classifies as system reliability, depreciation, expenses related to taxes, O&M, overhead expenses, and other expenses associated with the expansion program. To qualify for IERM treatment, a project must achieve a positive IRR when all costs associated with the project are considered. Moreover, the analysis must consider the projects entire life, not just the first six years. [FN17]

Further, the Department will require that the Company project and meet a four-year average of revenue for each project as a target. The Department believes that setting a target for expected revenue growth per project would encourage the Company to find new customers to connect to the system. The Department believes that the shareholders should maintain some of the risk associated with each project. Therefore, if the revenue target is not achieved, the Department will reduce the amount supported in the IERM by the difference. The Department will continue to monitor each project in the context of a rate case beyond four years until such time that the project achieves a positive cumulative IRR to determine whether the project's projections have been met. To the extent that projections have not been met, the Department will adjust the amounts allowed in rates accordingly.

4. System Expansion and Reliability

The principal element of reliability in the gas distribution business relates to the ability of the LDC to deliver adequate supplies of gas to its customers. The three main components of reliability are: a) acquiring adequate gas supplies; b) having the gas delivered to the relevant city gate station (the place where gas is transferred from the interstate pipeline system to the LDC); and c) moving the gas from the city gate station to the customer. The first two elements are largely contractual and addressed by the Department in its review of a company's gas supply portfolio. The third element of reliability relates to the ability of the LDC to deliver that gas.

The ability to deliver gas depends upon having adequate distribution mains to deliver gas from the interstate pipeline to the customer. If a main is fed from only one direction (a dead-end system), any interruption of that line will result in a service outage to all customers downstream of the interruption. If that main is served from two directions, the chances of an outage are greatly lessened because there is a bi-directional feed. Also, since problems on the interstate pipeline or at the gate station could occur, having the system fed by more than one of the interstate pipelines would increase reliability. Further, having excess capacity in the main from each direction so that one of the feeds alone could support the entire system would also increase reliability. Reliability could be increased even more by having two mains, each fed from two directions with each feed capable of handling the entire load. The interstate pipeline reliability could be addressed by having the four feeds for this system served by the three different interstate pipelines currently in Connecticut. This would limit exposure to just the service line, and that limitation could be addressed by having two service lines serve each customer, and have each service line connected to the two mains. Thus, it is possible to increase reliability significantly to the point where it is virtually impossible to have a deliverability failure. However, the required redundancy would result in greatly increased costs that would produce increased charges to customers greatly in excess of those currently in place.

Gas service in Connecticut was interrupted only once in the history of the interstate gas pipelines. This was when an excavator severed the sole interstate pipeline serving Torrington in April 1989. It resulted in an interruption to some 7,500 customers and cost more than \$1 million for relighting. At the time, the estimated cost of \$20 million -- \$25 million for a feed from Waterbury was viewed as being economically infeasible for such a low-probability event. See, Decision dated May 6, 1992, in Accident Docket No. 431, Report of Connecticut Department of Public Utility Control Gas Pipeline Safety Unit of the Examination into the Causes, Facts and Circumstances Connected with the Incident Occurring at Hayden Woods Estates, Torrington, Connecticut on April 11, 1989, in the Operation of the Plant and Equipment of the Tennessee Gas Pipeline Company and Yankee Gas Services Company.

While interruptions in the Yankee system from interstate pipeline are still possible, the likelihood is remote. The goal should not be to eliminate all risk of interruption but to deliver gas with an economically efficient level of reliability. Redundant mains and services may produce high costs for protection against incidents that have an extremely low chance of occurring.

While reliability is of major importance, its cost can be extremely high. Decisions regarding increased reliability need to measure the result of increased reliability against the costs of higher charges to customers. The ideal way to address reliability is in cases where increased growth in an area can support an investment that not only covers the increased delivery capability for the new customers but also include increased reliability. This includes interconnecting separate systems or providing a feed from a second direction or a feed from a different pipeline. In evaluating the need for increased reliability, it is necessary to balance the increased capabilities against the costs of the reliability enhancements. Finally, the Company needs to be aware that growth could at some point affect system reliability.

The Company has included in its list of IERM projects some that have very high reliability costs relative to their prospects for customer additions. If the Company is going to pursue projects where the costs of increased reliability are not covered by incremental system growth, it must carefully address the costs and benefits of any reliability component of proposed expansions. This will allow the Department to determine whether the proposed increases in reliability are proper, prudent, and cost-effective, or whether they are the result of inefficiencies or poor judgement on the part of the Company by allowing the system to grow imprudently.

5. Summary

The Department believes that expanding the gas distribution system can provide benefits to the state and ratepayers if performed efficiently and in a cost-effective manner. Therefore, Yankee is free to undertake construction as needed under the current, existing regulatory framework or process such as using the hurdle rate. With the Company's proposed IERM, the Department is concerned about the potential rate impacts that may be associated with the Company's proposal. While increased availability of natural gas may promote economic development, higher rates may offset this benefit. Therefore, expansion projects that fail the traditional hurdle rate test will be eligible to have their net costs supported by ratepayers provided that the impact on rates is minimized. The IERM approved by the Department is similar in concept to the Company's proposal, but will operate differently. The Department will hold annual IERM proceedings, as proposed by the Company, but those proceedings will consider both the performance of projects constructed in prior

years, and the Company's proposals for projects to be considered in the succeeding year. As proposed by the Company, the costs of IERM projects currently under way are in the costs that the Department is approving for the Rate Year (2002). The first IERM adjustment will be for 2003.

Given the complexity of the review contemplated by the Department for system expansion projects to be funded through the IERM, the Department will require that the Company's IERM proposal for each rate year starting January 1 be filed August 1 of the prior year. On August 1, 2002, the Company will file its proposal for IERM projects to be placed in-service during the period July 1, 2002 through December 31, 2003. The filing will contain the following information for each project: a detailed description of the project including length, diameter, and type of pipe including a map or sketch of the project; NPV; IRR; annual revenue; net revenue; capital cost per customer; total capital cost, including all system reliability costs; total number of potential and achievable customers along the project route per rate class; total number of customers that have signed contracts to receive service along the projected route, per rate class; and a projected annual and four-year average of revenues that does not include revenues associated with interruptible or ILEP customers. The Company will provide all other information necessary for the Department to determine that the criteria for qualifying for IERM treatment as defined below has been met. The Company will also be required to include in this filing its expectation as to the earnings that will flow through the ESM including any ESM true-up from prior periods.

Also by August 1, 2002, the Company will file information on the performance of IERM projects placed in-service in 2001 and through the first half of 2002. The filing will contain the same types of information as stated above for the upcoming rate year on an actual basis and include a comparison between the estimated costs and revenues for each IERM project included in the rate year and the actual amounts.

The Department intends to issue its first IERM decision prior to the end of the year to be effective in January. For each project, the Decision will include a) approval or modification of expenditures related to projects in-service by June 30, 2002; and b) a calculation of the amount of the annual IERM surcharge (if any) to monthly bills for calendar year 2003. The Decision will specify for each project those costs that will be recovered through the IERM.

Succeeding years' filings will be made by August 1. These filings will include the same type of information as the preceding year's filing updated by one year. Succeeding years' filings will also include detailed statements of costs and revenues from the IERM program on a project by project basis since the program's inception. Consideration and decision by the Department in the years after the first

one will include a) true-up of the IERM surcharge for the difference between estimated and actual project costs and revenues, and b) a netting of over-earnings (see discussion below) against the IERM revenue requirement.

The Department believes that projects qualifying for IERM treatment are those that:

- a. have a portion of the near-term benefits of the expansion in the form of greater availability of gas and/or enhanced reliability; and
- b. extend or expand the Company's existing distribution system; have significant costs; do not pass the existing hurdle rate calculation.

The IRR screen will include:

- a. all costs; [FN18]
- b. all projected revenues;
- c. a positive overall IRR that is calculated over a time frame of 30 years; and
- d. a cross-over to annual positive IRRs by year ten.

Also, the Department will scrutinize any costs claimed as reliability costs to determine certain factors. Reliability changes to the system should meet the expected future growth of existing and new customers and be economically efficient and viable. In addition, the Department will determine if the costs are needed to: resolve areas of low pressure; provide multiple feeds for system reliability; and/or provide for multiple pipeline supply.

Projects that qualify for consideration under the IERM may have some of their net costs supported by ratepayers provided that Yankee includes such projects in its annual IERM request and justifies the associated net costs as specified above. The annual filings will be reviewed, audited and, where appropriate, modified by the Department before requested net costs (or net revenues) are allowed to be flowed through the IERM. The Department has allowed certain IERM-related expenses as part

of the revenue requirements in this proceeding. Those expenses will be subject to review and true-up in the first IERM proceeding.

In summary, the Department will require that the Company demonstrate that there is a positive IRR, all construction costs have been prudently incurred, and that CIAC have been maximized. Further, for any project that has a total 30 year IRR less than 10%, the Department will cap the allowed charges through the IERM so that ratepayers do not fund the difference between the project's IRR and a 10% IRR. The ratepayer share of any and all Company overearnings for the concluding rate year will be used to offset costs to be recovered through the IERM. If these overearnings are not sufficient to make the expansion project viable given the assumed minimum 10% IRR, then the project's remaining net cost will be eligible for the IERM. These net costs will be reduced by the margins on interruptible customers that are part of the project. Ratepayers' share of overearnings not needed to offset IERM costs will be available through the ESM. The IERM will remain in effect as specified until modified or terminated by the Department in the public interest.

J. INTERRUPTIBLE LINE EXTENSION POLICY

[81-84] In the Decision dated February 4, 1988 in Docket No. 87-07-01, Application of The Connecticut Light and Power Company to Amend Its Rate Schedules, the Company (then part of CL&P) was allowed to implement a two-year trial ILEP. The Department authorized a maximum annual expenditure of 5% of net plant-in-service and a maximum individual expenditure of 1% of net plant-in-service. Decision, p. 15. The ILEP program allows the Company, at shareholder risk, to install and pay for all or a portion of main extensions to new interruptible customers. These capital additions are excluded from rate base until the full amortization of the asset's cost occurs over ten years. The revenue from sales or transportation service to each ILEP customer is used to repay all the expenses, such as taxes and depreciation, associated with service to each customer. Revenues in excess of the expenses plus the Company's allowed rate of return on the ILEP customer rate base are shared 50/50 by the Company and firm ratepayers. If ILEP revenues do not cover the project's expenses, shareholders absorb the loss. Ferrantino PFT, p. 12; Tr. 10/2/01, pp. 828 and 837.

By letter dated April 3, 1991, the Department approved the Company's request that it be allowed to continue the ILEP until it could be reviewed for permanent status in the next rate filing. In the Decision dated August 26, 1992 in Docket No. 92-02-19, the Department again continued ILEP as a temporary program subject to review in the instant docket. In that Decision, the Department authorized a five-year contract pricing agreement term (previously three years), increased the individual investment cap of 1% to 1.25% of total net rate base and continued the maximum annual expenditure of 5% of total net rate base. Decision, pp. 57 and 58.

In the instant docket, the Company requests that the Department:

1. approve the ILEP program on a permanent basis;
2. extend contract pricing agreements terms for periods of up to 10 years;
3. increase the investment cap per project to 4% of total net plant; and
4. increase the overall investment cap to 7% of total net plant.

Ferrantino PFT, p. 13

The Company indicates that since the ILEP's inception through September 30, 2000, the sharing mechanism has returned \$2,777,269 to firm ratepayers through PGA and deferred fuel calculations. Responses to Interrogatories GA-55 and GA-274. For the 12 months ended May 2001 the Company has provided service to 12 new interruptible customers and added 218 new natural gas customers along and beyond the ILEP routes. This represents an additional 557,270 Mcf of usage and \$974,450 of margin. ILEP extensions have enabled the Company to expand its service mains into previously unserved areas, adding new firm load on its system with little or no incremental investment by ratepayers for new mains. Ferrantino PFT, pp. 13 and 14.

The Company states that increasing the ILEP agreement term from 5 years up to 10 years will provide a better match for their ILEP investment evaluation and the standard depreciation period for ILEP assets. Also, previous ILEP customers have requested agreements with terms longer than five years. The Company states that longer-term agreements will provide ILEP customers with more price stability in a volatile market and provide a greater likelihood that projects will be profitable. Ferrantino PFT, p. 15; Late Filed Exhibit No. 100. The Company states that the longer term will provide it with the ability to implement more types of pricing tools in response to the increased competition that exists in the marketplace today. Tr.10/2/01, p. 829.

OCC recommends approval of the Company's proposal to make the ILEP program permanent. Further, OCC has no objection to Yankee's proposal to extend pricing

agreements for a period of up to 10 years. OCC is in favor of increasing the ILEP investment cap when tied to the IERM because it 'may provide a suitable alternative to the financially unacceptable projects that the Company has put forward as part of its IERM.' Additionally, OCC is skeptical about a blanket increase in the ILEP investment cap in the situation when an ILEP project's profitability is facilitated by ratepayer funding of an IERM project from which the ILEP project is built. Brief, pp. 113 and 114.

The Department notes that the 11-year financial track record of the ILEP resulted in a 50/50 sharing of approximately \$5,600,000 from September 30, 1990 to September 30, 2000. Response to Interrogatory GA-274. Also, at the end of the 10-year period during which the ILEP asset cost is fully amortized, the asset is transferred to the Company's rate base with service billed under tariff Interruptible Service (IS). The incremental margin related to that asset is then included in the calculation of IS margin sharing at the current rate of 80/20. Since the transfer is of an asset with zero book value, ratepayers provide no return on rate base after the asset is transferred. Tr. 10/2/01, pp. 835-837. In view of this record, the Department agrees with the Company and OCC that the program should be made permanent. In doing so, however, the Department wishes to have a clear understanding of what costs are to be covered by ILEP revenues prior to sharing excess margins between shareholders and ratepayers during the 10 years that each project is in the program.

As stated previously, the Company testified that the ILEP revenue covers all of the expenses related to providing service to these customers. The Department finds that Yankee's presentations on the ILEP mention fuel expense, depreciation, income taxes and allowed return. Response to Interrogatory GA-274. However, Yankee also testified that no operation and maintenance (O&M) expense is covered by ILEP revenues. Tr. 10/05/01, p. 969. In addition, no reference was made to property tax, and references to the Gross Earnings Tax are inconsistent. Responses to Interrogatories GA-334, GA-335 and GA-357. Without any allowance for those costs, the ILEP projects impose these costs on Yankee's firm customers. Based on the above, the Department finds that Yankee's presentations regarding the recovery of the ILEP costs inconsistent.

In making the program permanent, the Department will require the ILEP revenues to recover all incremental expenses. Further, when the Company computes the return under the ILEP program, the ILEP projects will be treated in aggregate. Revenues from each ILEP project must cover not only fuel expense (purchased-gas cost), return, income taxes and depreciation but also other costs. These include incremental O&M expense (such as inspection, maintenance, billing and collection, and meter reading, maintenance and repair), and incremental non-income taxes, including Gross Earnings Tax and property taxes. Finally, the Company stated that any revenues from firm customers who are also served by way of any ILEP project will not be considered ILEP revenues. Tr. 10/05/01, p. 968. The Department agrees.

The Department is also concerned that the ILEP not offer the potential for abuse. Yankee testified that customers sometimes come on as ILEP customers and then switch to firm service. Tr. 10/05/01, pp. 981-982. In line with the Company's testimony stated above, the Department assumes that the revenue from those customers is no longer counted as ILEP revenues. Id., p. 968. If all customers on a particular ILEP extension convert to firm service, it seems appropriate that those facilities also convert to firm service. Thus, if all customers being served by a particular ILEP extension convert to firm service, the costs of that extension should be transferred to the Company's rate base at its net book value. This is to be determined at the end of the month in which the last customer converts.

As part of making the ILEP program permanent, the Department will require an annual report starting with the rate year 2002. The annual report will include by individual customer: ILEP extension original costs and amortization to date; annual margin; margin contribution allocated to costs and return; and excess margin shared between ratepayers and shareholders.

Increasing the investment cap per project from 1.25% to 4% of total net plant, using the net plant balance as of June 30, 2001 of \$361,963,983, results in the current investment cap per individual project increasing from \$4,524,550 to \$14,478,559. Response to Interrogatory GA-174. The Company stated that it has a current potential project that could represent 3.6% of June 30, 2001 net plant, or \$13,030,703. Tr. 10/2/01, p. 832; Response to Interrogatory GA-174. Moving the current overall annual investment cap from 5% to 7% of the June 30, 2001 net plant increases this cap from \$18,098,199 to \$25,337,479. Response to Interrogatory GA-174. Despite the large proposed increases in spending caps, the Company asserts that these incremental ILEP construction projects would be subcontracted out and would not affect existing work forces at Yankee. Tr. 10/2/01, pp. 833 and 834.

The full financial risk associated with the Company's ILEP is borne by its shareholders, including the risk of not earning their allowed rate of return on ILEP investments. Tr. 10/2/01, p. 826. Ratepayers share in margins after the Company recovers its costs and return on rate base. New firm ratepayers added incrementally to ILEP projects provide additional firm Mcf volume and revenues with little or no ratepayer investment. The Department believes that revenues from these incremental firm customers resulting from initializing an ILEP project provides a balance to OCC's concern about firm customers supporting an ILEP project as part of the Company's proposed infrastructure expansion program. Based on the aforementioned, the Department believes that the ILEP program is in the public interest. Therefore, with the exception cited below, the Department approves the ILEP program on a permanent basis; extends the contract pricing agreements terms for periods of up to

10 years; and increases the overall investment cap to 7% of total net plant.

The Department is concerned that if the investment cap is increased it may allow large ILEP projects, such as gas-fired electric generation plants, to be added to the system without regulatory review. The large daily consumption of these plants may affect the integrity of the system as well as safety and reliability. Therefore, the Department will not approve an increase in the investment cap from 1.25% to 4% for an individual project. However, the Company can submit a proposal to the Department for a special contract for any ILEP project with an investment of more than 1.25%. The Department will require that the Company's submission contain the following: the contract between the Company and the **customer**; contract pricing terms; projected cost; projected percentage of net plant; map of the intended route, showing all potential **customers** along that route; size and type of pipe that is expected to be used; total daily available **capacity** at the beginning of the ILEP project; and the type of **customer** (e.g., power plant, manufacturing plant, residential, commercial), service rate, and projected daily consumption of each ILEP **customer** and other potential **customers** along the route.

K. OFF-SYSTEM SALES

[85] The Company's current margin **sharing** allocation of **capacity release** credits and off-system **sales** is 85% to the **customers** and 15% to the shareholders. Yankee proposed to change the allocation percentage split to 50/50 between the **ratepayers** and shareholders. The Company believes that all **sharing** mechanisms for **capacity release** credits, off-system **sales**, and interruptible margin **sharing** should be consistent in order to maximize the potential value for excess pipeline **capacity**. Additionally, Yankee believes that a 50/50 **sharing** of margin provides an incentive for the Company to strive to exceed the target margin in an increasingly volatile fuel price market. Further, Yankee states that the Department previously allowed uses of excess target margin, off-system **sales** and **capacity release** credits to offset transition costs associated with FERC Order 636. Soderman PFT, pp. 12 and 13.

OCC believes that off-system **sales** and **capacity releases** credits to **customers** are the result of transactions by the utility that occur outside its distribution system. Additionally, the gas supply used to perform these **sales** is the gas supply that has been purchased to meet firm **customers'** demands. Since firm **customers** are not using that excess gas supply, it is available to be sold to **customers** outside the **LDC's** distribution territory. Cotton PFT, p. 20. OCC recommends retaining the off-system **sales** and **capacity release** margin **sharing** percentages at the current level of 85% to the **ratepayer** and 15% to the shareholder. Cotton PFT, p. 21.

The Department agrees with OCC, and believes that off-system **sales** and **capacity release** credits result from excesses in **capacity** when firm **ratepayers** are not using that gas supply. Therefore, off-system **sales** and **capacity release** credits should be apportioned in a manner that favors the firm **ratepayers** to lower their monthly purchased gas costs. Further, shareholders receive 15% of the margin obtained from off-system **sales** as an incentive to encourage off-system **sales** and temporary **capacity releases**. The Department believes that the Company's argument that '...the **sharing** should be consistent because that would provide an opportunity to use all three markets; interruptible **sales**, off-system **sales** and temporary **capacity releases**, equally in order to maximize potential value for excess pipeline **capacity**' is unfounded. The Department believes that interruptible **sales**, **capacity release**, and off-system **sales** are only equal because the LDC can recall each when the gas supply is needed by firm **customers**. Since off-system **sales** and **capacity releases** occur outside the LDC's service territory, they tend to have contract periods that may be as short as one day. The margins derived from selling these **assets** on the secondary market can change daily, depending on the availability of the **capacity** that market during that day. While interruptible **customers** receive service within the LDC's service territory, the value of the margins derived from the interruptible **customers** depends on the type and cost of that customer's alternate fuel. Based on the aforementioned, the Department does not accept the Company's proposal to change the **sharing** mechanisms for off-system **sales** and **capacity release** credits. The Company will retain the current off-system **sales** and **capacity-sharing** split of 85/15.

L. HEDGING

[86, 87] Hedging is defined as the practice of offsetting the price risk inherent in any cash market position by taking an actual but opposite position in the futures market. The Department addressed the issue of hedging in the Decision dated July 8, 1994, in Docket No. 94-01-12. In this Decision the Department sought to balance the risks and rewards of the futures market between firm ratepayers and stockholders. The Department allowed each of the state's three local gas distribution companies (LDCs) to use the futures market for up to 10% of its gas supply portfolio, with resulting profits being split 80% to firm ratepayers and 20% to stockholders. Because the LDCs have control over gas supply decisions, the Department decided that the risk of those decisions must be borne by the LDCs. Therefore, the split for losses was allocated 20% to firm ratepayers and 80% to stockholders. This split does not apply to individual contracts where all the risk and reward is borne by a specific customer. However, it does apply to individual contracts where the LDC assumes the risk. Decision, p. 25.

Yankee's Application in the instant proceeding did not include a request for

changing the Department's directives on hedging activity. Yankee states that it is interested in engaging in a dialogue with the Department and other interested parties to determine the value of altering the Department's current policy on hedging activities. Yankee believes that the instant rate proceeding is not the proper forum for discussing the issue of hedging. Late Filed Exhibit No. 61.

OCC urges the Department to initiate a gas hedging generic docket in order to stabilize gas commodity costs and lessen the impact of gas commodity price volatility on ratepayers. Due to the fact that none of Connecticut's LDCs are engaged in hedging OCC advocates a change in the Department's current policy to provide for hedging which, in their opinion, will stabilize gas commodity prices. Brief, p. 147. OCC believes that a gas hedging program should consist of at least four basic approaches that will serve to balance price risk and stabilize prices to ratepayers that are indexed based contracts, fixed price contracts, purchase of futures, and purchase of call options. OCC acknowledges that the cost of a gas hedging--program may increase the cost of gas due to commissions paid to commodity brokers. Brief, p. 149. The other parties and intervenors were silent on this issue.

The Department has determined that the question of hedging should take into consideration all three of the state's LDCs. Although the orders on hedging from Docket No. 94-01-12 remain in effect, the Department finds that the issue of hedging should be taken up anew in a generic proceeding. This proceeding would include all three of the state's LDCs similar to the continuation of the unbundling proceeding in Docket No. 97-07-11, DPUC Generic Investigation into Issues Associated with the Unbundling of Natural Gas Services by Connecticut Local Distribution Companies -- Phase I. The Department ruled in a similar manner in the Decision dated August 31, 2001, in Docket No. 99-09-03 Phase III.

M. LNG FACILITY

1. Company Proposal

[88, 89] Yankee proposed to construct a liquefied natural gas (LNG) production and storage facility. The Company's proposal included adding the costs associated with the LNG facility as part of its infrastructure expansion program. The purpose of the facility would be to improve supply reliability and system flexibility. At the time of its rate increase filing, Yankee was still evaluating facility design questions. This included such items as storage capacity and liquefaction and re-vaporization rates, and the Company had not selected a site for the facility. While this analysis is continuing, the Company stated that it is important for the Department to indicate its concurrence with Yankee's LNG plant plan in this Application. This is

due to the fact that it is likely to be the only rate case between now and the facility's in-service date. Andrukiewicz PFT, pp. 4 and 5. The Company also requested that the LNG facility be considered one of the projects to be covered by its proposed IERM. Soderman PFT, p. 8.

The Company made considerable progress in finalizing the proposed facility during the time that this proceeding was in progress. About three weeks after the Company's initial filing, a preliminary engineering report was completed and submitted to the Department. Response to Interrogatory GA-41. That report was used as the basis for a technical meeting, held at the Department's offices on October 9, 2001 to discuss design and safety issues. At the end of the hearings in this proceeding, the Company announced that it had selected its Waterbury operations center on Eagle Street as the preferred site for the facility. It appeared that the Company had selected the larger of the two facility-size options that were under consideration, and that the double-containment spill-impoundment design had been selected. Response to Interrogatory GA-38-RV01.

Yankee believes the LNG facility can be used for the following operational functions: peak shaving, system reliability assurance, system balancing, managing hourly swings and pipeline tolerances. The Company asserts that the construction of the LNG facility would enable it to meet its supplier of last resort responsibilities. Further, the Company believes that the LNG facility would add assets to its portfolio to meet incremental customer demand. Responses to Interrogatories GA-48, GA-183, GA-183-SP01, GA-184, GA-184-SP01 and GA-340; Andrukiewicz PFT, p. 6. The Company proposed to begin construction of the facility in 2002, thereby allowing for a three-year construction schedule. Yankee projected the facility would enter service late in 2004. Andrukiewicz PFT, pp. 4 and 7.

OCC argues that the LNG facility is not needed. OCC believes that the Company will have more than sufficient design-day capacity for the next several years. Further, the Company has access to lower-cost alternatives for its gas peaking requirements. OCC also believes that if the Department eliminated the supplier of last resort obligation of the Company, the need for peaking capacity would no longer exist. Brief, pp. 114 and 115. Neither the AG nor CIEC expressed an opinion regarding the proposed LNG facility.

2. Department Analysis

The Department believes that approval of the proposed plant as an IERM project is premature. In particular, since the location of the proposed facility has only just been decided, significant uncertainties remain regarding the project's construction

costs. Site work must be designed and costed out in more detail, safety measures including those discussed below must be finalized and costed out, and required modifications to the Company's distribution system must be engineered and costed out.

The Department is also concerned about a number of aspects of cost recovery and cost incidence in the rate treatment proposed by the Company. First, the cost-benefit analysis presented by the Company during the rate case is inadequate. The addition of a peaking facility to a company's gas supply capacity portfolio could result in significant changes to the portfolio over time. Those future portfolio adjustments could result in cost reductions that offset some, if not all, of the peaking facility's costs. The Company's analysis to date has not addressed these questions in sufficient depth. Responses to Interrogatories GA-48, GA-183, GA-183-SP01, GA-184, GA-184-SP01 and GA-340.

The Department believes that the intended use of the LNG facility for the operational parameters the Company proposed would have an important bearing on design questions such as facility size and vaporization rates. Additional details of these uses should be an important consideration in both the final specifications for the facility, and in the design of the rates through which Yankee will recover its costs. Further, the Department believes that the proposed uses for the LNG facility may affect the cost to build the plant. The Company has not provided sufficient detailed information relating to these issues in the instant docket.

Finally, the Department is concerned about costs vs. benefits included in the Company's studies. Therefore, the Department will require detailed cost and benefit information on major project design questions, such as the presence and sizing of the liquefaction capability that is included in the proposed LNG facility. The Department will determine the timing of the submission of this information at the technical meeting discussed below.

The Department is supportive of Yankee's efforts on this project to date, and looks forward to receiving satisfactory answers to its questions. The Department will re-open this proceeding to consider additional information on the proposed LNG facility as soon as feasible. The Department will hold a technical meeting to assess the Company's progress in developing the project and to discuss any additional information that the Department needs to quickly reach the necessary decisions. Therefore, the Department will not include any LNG expenses in the instant Decision. Further, the LNG facility will not be included as an IERM project at this time.

3. LNG Plant Safety

[90, 91] Safety jurisdiction over the LNG plant rests with the Department, and is administered by the Gas Pipeline Safety Unit (GPSU). The LNG plant must comply with 49 CFR 193, Liquefied Natural Gas Facilities: Federal Safety Standards. The 49 CFR 193 safety standards largely reference the National Fire Protection Association (NFPA) 59A Standard, Standard for the Production, Storage, and Handling of Liquefied Natural Gas (LNG). Both of these sets of safety standards are the minimum safety standards that must be followed to site, design, construct, initially test and operate and maintain an LNG plant. In numerous places, NFPA 59A provides that the authority having safety jurisdiction may make modifications it deems necessary to provide for a greater level of safety. It should be noted that these standards are engineering standards designed to deal with safety issues that arise from the chemical and physical properties of materials used to construct the facility, the fluids located at the facility, and natural events that could affect the facility. They do not address issues of intentional acts against the integrity of the facility.

In addition, Conn. Gen. Stat. §16-11 states, '[t]he department may order such reasonable improvements, repairs or alterations in ...plant or equipment, or such changes in the manner of operation, as may be reasonably necessary in the public interest.' The Department has determined that additional safety precautions are 'reasonably necessary in the public interest.'

The Company proposed to construct the LNG tank using a double containment cryogenic storage tank design. Both the inner and outer tank would be constructed of concrete with a carbon steel layer for vapor containment. In this design, if the inner tank were to fail, the outer tank would contain the LNG. The Company states that this type of design allows the LNG plant to be sited in an urban setting. Response to Interrogatory GA-41, pp. 16 and 17. Due to the double concrete tank, the design does not include a dike surrounding the tank to contain the entire contents of the tank in case of catastrophic failure.

The other two large LNG tanks in the state use a cryogenic inner tank, with a non-cryogenic carbon steel outer tank, which would not contain the cryogenic LNG. Therefore, an external impoundment system is required. This external impoundment system is essentially a large area around the tank that has been excavated. The volume of this excavated area is at least equal to 100% of the volume of the LNG stored in the tank. With Yankee's proposed double containment tank design, if the inner and outer tanks were to both fail, the LNG would not be retained since there is no external impoundment system. The Company stated that there is essentially no threat that would cause both the inner and outer tanks to fail. Response to Interrogatory GA-41 and Late Filed Exhibit No. 54.

The Department does not find the information provided and the assumptions made sufficiently convincing. The Company was asked during the hearing to estimate the cost of adding an external impoundment system. The Company responded that the cost would be approximately \$300,000 for an earthen berm. Tr. 10/9/2001, p. 1222. However in Late Filed Exhibit No. 54, the Company rejected this method because of concerns about possibility that the soil on the site was contaminated. The Company substituted a large concrete structure at an estimated cost of \$3,000,000. The Department has concerns regarding whether an external impoundment system is necessary and whether the originally proposed \$300,000 solution might be viable. Therefore the Company will be required to meet with the GPSU as part of its on-going routine activities. The purpose will be to determine what further studies of the storage tank and possible impoundment areas need to be performed and what the final design should be.

The Waterbury site chosen by the Company for the LNG plant currently contains a propane-air peak shaving plant that will be in close proximity to the LNG storage tank. It is also close to offices and facilities for service technicians and street crews for Waterbury, and systemwide warehousing and other engineering services. This peak shaving plant contains approximately 900,000 gallons of liquid propane stored in 19 tanks. The peak shaving plant was built in the early 1960's using the appropriate safety codes as they existed at that time. The safety codes of the 1960's did not address many areas that are in today's codes and the codes certainly did not anticipate an LNG storage tank to be built within approximately 500 feet of the propane tanks. Also, there is no impoundment area at the propane plant to contain leakage of propane in case of a failure. Further, some of the propane tanks are oriented such that a significant incident, such as a BLEVE (boiling liquid expanding vapor explosion), could propel large sections of 30,000 gallon propane tanks into the LNG tank. Response to Interrogatory GA-41, p. 8.

The potential that an incident at the LNG plant could adversely affect the propane plant, or alternatively an incident at the propane plant could adversely affect the LNG storage tank, concerns the Department. During the hearings, the Company proposed adding a water curtain or water monitors pre-aimed at the propane tanks. The Department does not believe that adding these safety measures is sufficient to protect either facility from one another. Tr. 10/9/01, pp. 1189 and 1190. The Department therefore will direct that the propane storage tanks at the Waterbury facility be deactivated and purged of propane prior to LNG being introduced into the LNG storage tank. Further, the Company will not be allowed to store any propane in the tanks while the LNG storage tank remains in service (i.e., contains LNG).

The Company proposed that the LNG plant be locally attended five days per week, day

shift only, and be remotely attended by the Yankee Control Group located in Meriden during the balance of the hours. Response to Interrogatory GA-41, p. 26. The Department is concerned about leaving an LNG facility unattended for the majority of time. The potential exists for small problems to escalate into large problems during the time it would take for plant operating personnel to be dispatched to and arrive at the facility. Having a competent, qualified and fully trained LNG plant operator onsite at all times would dramatically decrease the potential for small incidents to become full-scale emergencies, and provide immediate capability to evaluate and deal with incidents. The Department evaluated the amount of energy to be stored at the facility, the potential impact on public safety and the safety of the large number Company personnel located at the Waterbury facility, the claimed significance of the facility to meeting the gas supply needs of Yankee's customers and the amount of capital involved in the facility. The Department believes that the LNG plant should be staffed onsite, 24 hours per day, every day, by dedicated, competent, qualified and fully trained, LNG plant operators whenever LNG is present at the facility.

The Company filed only a preliminary engineering report with the Department at this time. The Department will require final engineering designs to be filed with the GPSU for review prior to the commencement of construction. The Company must receive approval from the GPSU before commencement of construction. Operations, maintenance and emergency procedures must also be approved by the GPSU prior to LNG being introduced into the LNG storage tank. The complex nature of the LNG plant, the approximate three-year time schedule to construct the plant and the extensive amount of activity involved in the project will require close monitoring by the Department. Therefore, the Department will exercise the authority it has under Conn. Gen. Stat. §16-8(b)(2)(C) to engage the services of a consultant to assist the GPSU in reviewing the siting, design, construction, initial testing and operation and maintenance of the LNG plant.

N. GAS PIPELINE SAFETY

1. Cast Iron/Bare Steel Program

[92, 93] The physical facilities of the Company include a large amount of underground plant, some of which is modern and state of the art (coated, cathodically protected steel and plastic) and some not of modern materials (bare steel and cast iron). The Company has an ongoing program to evaluate its physical facilities, particularly those that are not 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 not 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 not state of the art is desirable, it is a long-term

process.

In Docket No. 00-01-11, the Department stated that the replacement program was an area that Yankee needed to review in greater detail in the future with an eye toward accelerating the rate of replacement. The Company proposed an accelerated replacement program essentially doubling from \$10,000,000 to \$20,000,000 the capital expenditures for replacement projects. Beschler PFT, pp. 13 and 14. The Department concludes that it is in the public interest for the Company to accelerate its replacement program. The Company should continue to replace facilities based on the priorities it has established according to its risk analysis of the affected facilities.

2. Meter Set Installations

[94-96] Generally, Company-owned and installed facilities at a customer's premises are installed properly and in accordance with applicable statutes, regulations and government orders. However, subsequent actions by customers, such as the installation of non-gas facilities in close proximity to the gas facilities, have endangered the gas facilities. To maintain the safety and integrity of the gas system, and to avoid the general body of ratepayers bearing the expenses due to the actions of a customer, it is appropriate that the customer be made responsible for any additional costs occasioned by that customer's actions. Therefore, the Department directs the Company to add the following language to its Rules and Regulations when they are filed in the next phase of this rate case:

If the use of the property changes after the Company has installed its facilities for rendering service and such new use may endanger the gas facilities or be in violation of any applicable statute, regulation or other governmental orders, it shall be the responsibility of the customer to bear the cost of all relocations and/or repairs.

O. TERMINATION NOTICE

[97] Yankee's termination notice envelope does not include any alert to customers that a shut-off notice is enclosed nor did the shut-off notice provided to the Department give the customer the correct amount of time in which to pay the bill. The Company indicated that the termination envelope will be modified to include the phrase 'Urgent Notice Enclosed' in bold text. In addition, the notice itself will contain more pronounced text to alert customers. These modifications were expected to be completed by December 31, 2001. Late Filed Exhibit No. 115. Response to

Interrogatory CA-2-SP01. The Company will be directed to file these modifications with the Department.

The Company's sample standard bill form and estimated billing procedure submitted to the Department for examination are in order. Responses to Interrogatories CA-1 and CA-4. Finally, Yankee's complaint records, though extensive regarding its internal process of record keeping and logging complaints, are appropriate. Response to Interrogatory CA-7. As ordered in the Yankee and NU merger Decision, the Company will continue to file its complaints record quarterly with the Department.

P. UNREGULATED AFFILIATES

1. Background

[98-102] Prior to its merger with NU in March 2000, the Company was part of the Yankee Energy System, Inc. (YES). YES was the parent company of several operating and non-operating subsidiaries, including Yankee. Since YES did not own any tangible property or have any direct employees, Yankee performed a wide variety of functions on behalf of all YES subsidiaries. Generally, the costs for these services were allocated to all benefiting affiliates. OCC states that while some costs were directly charged by Yankee to specific benefiting subsidiaries, the majority of affiliated costs were allocated to all subsidiaries based on the Massachusetts formula. Brief, p. 125. This formula takes into consideration three components: net plant, gross revenues, and payroll costs to determine the allocation percentage.

Yankee states that as a result of the merger with NU, Yankee is part of a much larger corporate entity that has extensive unregulated operations. Yankee shifted from a provider of affiliated services to a recipient of such services. Many of the services previously provided by Yankee are now being provided by NUSCO. NUSCO also provides centralized support services to other companies within the NU system, including several regulated and unregulated entities that provide a range of competitive services. Response to Interrogatory GA-219.

2. Cost Allocation

The Company testified that a merger transition team determined that providing services from a centralized service company was more cost-effective to Yankee than Yankee getting the service itself. Tr. 10/5/01, pp. 1016-1017. NUSCO provides

services at cost to all the subsidiaries of NU. Services provided by NUSCO to Yankee that the Company formerly provided itself include: accounting, administrative services, claims and insurance, corporate communications, environmental, safety and ethics, facilities, governmental affairs, human resources, information technology, internal audit, security, legal, purchasing, regulatory affairs, transportation and treasury. It was determined that some functions were more cost-effective to Yankee if it provided those services itself. Among these services are budgeting, planning, and some financial services. Tr. 10/5/01, pp. 1025 and 1026.

NUSCO and Yankee employees directly charge the appropriate affiliate whenever possible. Costs that are not directly charged to an affiliate are allocated to the various operating companies. Many of these costs are allocated based on payroll or number of employees in each affiliate. The specific allocation rates and the formulas used are filed annually with the Securities and Exchange Commission (SEC). The allocation methodology used by NUSCO differs from the Massachusetts formula that Yankee formerly used. Yankee testified that affiliates, Yankee Energy Financial Services and NorConn Properties, Inc. (NorConn) a real estate subsidiary of Yankee, provide services to Yankee. Although RMS still provides services to Yankee, it is no longer an affiliate of the Yankee system. The Company testified that while NUSCO provides services at cost to its subsidiaries, NorConn is allowed to receive a rate of return on the facility investment, plant in-service. Tr 10/5/01, pp. 1012, 1013, 1016, 1017, 1029, 1039; Response to interrogatory OCC-108; Response to Interrogatory OCC-119.

Yankee states that it and its subsidiaries are not formally subject to any gas-specific Codes of Conduct established at either the state or federal level. However, Yankee acknowledged that it would adhere in spirit to the Connecticut Code of Conduct that governs electric distribution company affiliate transactions. Response to Interrogatory OCC-122.

OCC acknowledged that the cost allocation methodologies and practices used by NUSCO to allocate costs appear to be well documented. Crane PFT, pp. 7 and 8. Therefore, OCC is not recommending any adjustments to the allocation factors currently used by NUSCO. However, OCC believes that it is important for the Department to retain jurisdiction and oversight over these allocations. Brief, pp. 125 and 126. OCC states that transactions between non-affiliated entities are conducted at 'arms-length,' usually the result of a bidding process or reflect prices and other information that is available to the public. Further, parties in non-affiliated transactions have an incentive to make the best possible arrangements, with no incentive to subsidize the each other. Brief, p. 131. To ensure the same arms-length in affiliated transactions, OCC recommends that the Department implement a reporting mechanism for all transactions involving Yankee. This mechanism should review and evaluate the affiliated services being provided to Yankee and have a forum for

determining the appropriateness of these costs. Brief, p. 130. OCC recommends that the Department require the following information from Yankee on an annual basis:

1. a listing of all affiliated companies;
2. all contracts entered into with affiliated companies, and a description of any transactions undertaken with affiliates without written contracts;
3. the total costs incurred by NUSCO, the amount charged by NUSCO to each affiliate, and the basis for the charges;
4. a list of all allocation factors used to allocate NUSCO costs to affiliates;
5. the total NUSCO costs charged to Yankee, by account;
6. a breakdown of NUSCO charges to Yankee, showing charges that were
 - a. directly charged;
 - b. allocated based on costs causative factors; and
 - c. allocated based on global allocation factors;
7. the total costs charged to Yankee by other NU affiliates and the basis for the charges;
8. a list of all allocation factors used to allocate other affiliated costs to Yankee;
9. a breakdown of charges to Yankee by each other affiliate, showing charges that were:

- a. directly charged;
- b. allocated based on cost causative factors; and
- c. allocated based on global allocation factors;

10. the total cost charged to other NU affiliates by Yankee and the basis for the charges;

11. a list of all allocation factors used to allocate costs from Yankee to other affiliates; and

12. a breakdown of charges from Yankee to each other affiliate, showing charges that were:

- a. directly charged;
- b. allocated based on cost causative factors; and
- c. allocated based on global allocation factors.

Brief, pp. 131 and 132.

The Department understands the importance of conducting affiliate transactions at arms-length and that the proper allocation methodologies are used to ensure appropriate costs are recovered by those affiliates that incur those costs. In order to ensure this, proper Department oversight is required. Therefore, the Department concurs with OCC's recommendation to require the Company to file an annual report detailing transactions with affiliates as described above. The Company will be directed to file an Affiliate Transaction report for review by the Department on an annual basis.

3. Asymmetric Pricing

Although OCC believes that NU and NUSCO appear to have detailed and extensive methodologies for distributing costs to various entities, it does not believe that the documentation considers whether the services provided are needed. Further, it needs to be determined if the allocation of costs from the affiliate is the correct method for charging ratepayers for their fair share of the services and if the use of an affiliate is the most cost-effective means of procuring the services. OCC states that the Company has not provided any justification for the use of NUSCO to perform these services instead of obtaining such services from a third party. For example, OCC questions what it would cost for Yankee to obtain similar services in the open market. OCC argues that Yankee should be able to demonstrate that the costs being incurred for affiliated transactions are no greater than what it would cost from a third party. Brief, pp. 132-135.

OCC recommends that corporate governance and common support functions be charged to all subsidiaries based on fully distributed costs. Costs for all other services, including all service company services that are available from third parties, should be priced at the higher of cost or market. This methodology is known as asymmetrical pricing. An asymmetrical pricing standard states that goods or services that are provided by a regulated utility to its affiliate should be priced at the higher of cost or market price, while goods and services provided by a non-regulated affiliate to a utility should be priced at the lower of cost or market. OCC also recommends that any services provided by Yankee to a non-regulated affiliate be priced based on asymmetric pricing. Id., 133 and 134.

Asymmetrical pricing is recommended by NARUC in its 'Guidelines for Cost Allocations and Affiliated Transactions,' which were adopted July 23, 1999. Id., p. 135. OCC states that asymmetrical pricing can be an excellent safeguard against cross-subsidization, particularly if accompanied by the appropriate regulatory oversight. Based on Late Filed Exhibit No. 126, asymmetric pricing is the most commonly used pricing methodology in states that have adopted a formal transfer pricing mechanism. OCC recommends that the Department open a generic docket to examine the issue of asymmetric pricing and its adoption for all Connecticut utilities. Brief, p. 135. OCC acknowledges that the vast majority of centralized services provided by NUSCO would still be on a cost basis, even if asymmetrical pricing were adopted.

The Department believes that this is not the appropriate docket to review this issue and may do so in a future docket.

4. NorConn

The Company states that the services provided to Yankee from NorConn for rental property are charged to Yankee at a level to achieve a rate of return consistent with the allowed rate of return in the Decision dated July 9, 1997 in Docket No. 96-08-05. Response to Interrogatory OCC-119. NorConn is the subsidiary that owns and operates the facilities used by Yankee. Yankee testified that that 'these types of items are included in rate base as plant in-service' which would allow a rate of return. Tr. 10/5/01, p. 1027.

In reviewing the NorConn Properties Lease (Lease) OCC argues that the Lease does not require the use of the utility's authorized cost of debt or capital structure. The lease payment is not based on Yankee's overall rate of return applied to net investment, but only on discrete financing costs that have been determined specifically for the properties that are the subject of the Lease. OCC argues that the Lease between NorConn and Yankee should be priced at rates that reflect Yankee's overall cost of capital. Brief pp. 137 and 138.

The Department finds that OCC raises an important concern that Yankee not incur greater expense in its interaction with affiliates than it would incur providing services on its own or from a nonaffiliated entity. Prudent management requires that utilities, including Yankee, obtain necessary services and facilities as cost effectively as possible. In some instances, this will mean obtaining these services or facilities from an affiliate. In such cases, it is vital that Yankee be able to demonstrate that obtaining services or facilities from an affiliate is cost effective relative to providing the services or facilities on its own or from a nonaffiliated entity. While the Department does not find, in this proceeding, that Yankee's Lease with NorConn is improper, the Company is cautioned that interactions with affiliate companies must adhere to the highest level of propriety and management efficiency.

III. FINDINGS OF FACT

1. The test year is the 12 months ending September 30, 2000.
2. The allowance for cash working capital includes recognition of the prepaid nature of property taxes.
3. Due to the NU/Yankee merger, Yankee has a regulatory pension liability of

\$39,253,000.

4. The amount by which the pension liabilities are overfunded cannot be utilized by the Company, which receives no time value of money from it.

5. The regulatory pension liability of \$39,253,000 is recorded as a debit to prepaid pensions with the offsetting credit booked as a deferred regulatory liability which is to be amortized over 15.82 years as a credit to pension expense.

6. SERP is an extra benefit payable to a select group of executives above and beyond the general Yankee pension plan.

7. The SERP is not deductible for income tax purposes.

8. Ratepayers effectively fund the extra benefit of the SERP in advance without receiving any reduction in taxes for it and have not been provided a credit for the advance.

9. The gross sales price for the Bethel land sale is \$3,600,000.

10. In the second quarter of 2001, the Company recorded a true-up to the transition credits of \$1.045 million.

11. In previous rate cases, Yankee used the National Oceanic and Atmospheric Administration (NOAA) 30-year normal, based on data from 1961-1990, when developing its sales forecasts.

12. The NOAA officially issued data for the 30-year period 1971 through 2000 is not available.

13. The Company's data shows that the actual weather for the test-year period was warmer than normal as defined by the current 30-year and 20-year average.

14. Flat rate pricing for service work is not common in the gas utility industry, nor is it common for plumbing or electrical service work.

15. Under a flat rate pricing structure, it is possible for a customer to be over-charged for a particular job that may not take as long as was anticipated in the Company's statistical analysis or to be undercharged.

16. The current target margin provides the Company with enough incentive to maximize net margins for the benefit of both shareholders and ratepayers.

17. Rate year expenses associated with rental and maintenance of the Company's Meriden corporate headquarters are nonrecurring because the Company moved its headquarters to Berlin.

18. The ALG procedure approximates the consumption of an account's production value better than the ELG procedure because ELG assigns equal cost recovery to assets in an account regardless of the expected life of those assets.

19. A 9% return on pension plan assets is representative of historical returns on a diversified pension portfolio.

20. The regulatory asset established due to the NU/Yankee merger represents the accumulated post retirement benefit obligation in excess of the fair value of the plan assets as of March 1, 2000.

21. The sale of RMS decreases the FAS 106 expense level by \$171,000 and the FAS 106 annual amortization by \$20,000.

22. Yankee revised its deferred and unrecovered FAS 106 balance at the start of the rate year, January 1, 2002, to \$2,821,515.

23. Yankee's revised its deferred FAS 106 deferred balance from the original estimated beginning of rate year amount of \$3,474,000 down to \$2,821,515.

24. The 401(k) plan average match rate is 2.26%.

25. Timely environmental remediation is in the public interest, because it is important for utilities to clean sites as soon as possible to avoid escalating costs.

26. Yankee's expenditures of \$12,609,693 on coal-tar remediation, since its last rate case, are prudent.

27. Including projected environmental remediation costs in revenue requirements would be an a priori approval of an expense that is allowed to be deferred between rate cases.

28. The Company's proposed Fuel Diversity Fund encourages fuel switching.

29. The Company resubmitted a revised property tax expense of \$9,621 to remove the sale of land in the town of Bethel and a tax settlement reached between Yankee and the Town of Meriden.

30. The NU/Yankee merger was consummated in March of 2000, therefore the test year reflects seven months of synergies.

31. Yankee's share of the merger synergies is approximately 50% of the higher total synergies that were ultimately identified by the transition teams.

32. Both Yankee and NU reflected the recommendations of the Transition Teams in developing their budgets.

33. Yankee does not maintain supporting information for their budgeted accounts in a centralized location.

34. Yankee used the GDP price deflator as a measure for inflation.

35. After the Company merged with NU in March 2000, 76 employees were transferred

from Yankee to NUSCO.

36. The Company's marketing efforts to acquire new customers and promote system expansion are aimed at gaining customers currently served by other fuel sources.

37. The Company used actual 1999 property tax assessments obtained October 1, 2000 and adjusted each town's mill rate to estimate rate year property taxes of \$10,148,000.

38. The property tax refund received by the Company from its settlement agreement with the City of Meriden relates to transactions that occurred in between rate cases, and refunded a property tax increase that occurred subsequent to the Company's last rate case.

39. The relief offered to the Hardship and MPP Programs through application of transition credits expired in September 2000, and is no longer available to the Company to minimize its deferred balances in these accounts.

40. Factors that are no longer present caused a spike in gas costs during the year 2000.

41. The number of drilling rigs and the level of storage injections increased in 2001.

42. The risk premium approach can be influenced by the period of time over which the stock-bond yield spread is measured, and the average bond maturity chosen.

43. The risk premium approach lacks predictive value, and does not account for changes in the riskiness of debt versus equity over time.

44. Estimates of earnings growth alone are inadequate to estimate expected growth in dividends and capital appreciation.

45. A more comprehensive earnings growth rate analysis considers recent sustainable growth and historic trends in earnings, dividends and book value.

46. The average dividend yield for the proxy group is 4.85%.
47. The projected growth rate for the proxy group is 5.91%.
48. The adjusted dividend yield for the proxy group is 5.0%.
49. Yankee does not have a weather normalization adjustment.
50. Short-term debt will likely be less than CWIP during the rate year.
51. The overall rate of return on rate base is 8.91%.
52. Yankee conducts and tracks monthly customer satisfaction through surveys.
53. Yankee has reported monthly ASA statistics that do not include abandoned calls that are well over the proposed 45-second benchmark.
54. Yankee's Service Call Responsiveness benchmark year to date average is 84.40%.
55. Using an arithmetic average to calculate performance under the SQP could conceal poor performance in the short term.
56. The ILEP program allows the Company, at shareholder risk, to install and pay for all or a portion of main extensions to new interruptible **customers**.
57. Revenues in excess of the expenses plus the Company's allowed rate of return on the ILEP **customer** rate base are **shared** 50/50 by the Company and firm **ratepayers**.
58. Since ILEP's inception through September 30, 2000, the **sharing** mechanism has returned \$2,777,269 to firm **ratepayers** through PGA and deferred fuel calculations.

59. ILEP extensions have enabled the Company to expand its service mains into previously unserved areas, adding new firm load on its system with little or no incremental investment by **ratepayers** for new mains.

60. The Company's current margin **sharing** allocation of **capacity release** credits and off-system **sales** is 85% to the **customers** and 15% to the shareholders.

61. The LNG plant must comply with 49 CFR 193, Liquefied Natural Gas Facilities: Federal Safety Standards.

62. The potential is significant that an incident at the LNG plant could adversely affect the propane plant, or alternatively an incident at the propane plant could adversely affect the LNG storage tank.

63. Having a competent, qualified and fully trained LNG plant operator onsite at all times would dramatically decrease the potential for small incidents to become full-scale emergencies, and provide immediate capability to evaluate and deal with incidents.

64. Yankee's termination notice envelope does not include any alert to customers that a shut-off notice is enclosed nor did the shut-off notice provided to the Department give the customer the correct amount of time in which to pay the bill.

65. Many of the services previously provided by Yankee are now being provided by NUSCO.

66. Affiliate transactions conducted at arms-length using proper allocation methodologies ensure appropriate costs are recovered by those affiliates that incur those costs.

IV. CONCLUSION AND ORDERS

A. CONCLUSION

Based on the evidence presented, the Department concludes that revenues of approximately \$317,691,287 will be sufficient to enable Yankee to operate successfully, maintain its financial integrity, attract capital, and compensate its investors for the use of their money and the risks assumed. Therefore, the Department decreases the Company's revenue requirements by \$4,006,000 or 1.25%. Pending a Decision in Phase II of this proceeding, the Company will apply the decrease uniformly to firm ccf sales, including seasonal customers. Dividing the \$4,006,000 decrease by total annual firm sales of 33,268,670 Mcf results in a credit of \$0.0120414/ccf. For the purposes of this calculation, NOAA monthly issued data from the period 1971-2000 will be used to normalize pro forma revenue. For a residential heating customer using 150 ccf, it is a \$1.81 monthly decrease which is subject to change as a result of the Department's determination in Phase II. The revenue decrease is effective by March 1, 2002.

B. ORDERS

For the following Orders, please submit one original and fifteen (15) copies of the requested material to the Executive Secretary, identified by Docket Number, Title, and Order Number.

1. No later than noon on February 8, 2002, the Company shall provide a sample bill applying the credit and a copy of the bill insert explaining the rate reduction ordered herein.

2. On and after March 1, 2002, the Company shall apply a \$0.0120414 per ccf credit for service rendered to firm customers and eligible special contract customer bills. The credit shall appear as a separate line item on customer bills.

3. No later than February 15, 2002, the Company shall request a technical meeting to discuss certain issues pertaining to Phase II in the instant docket.

4. No later than February 15, 2002, the Company shall request that a technical meeting be held to: a) assess the Company's progress in developing the details of its proposal for an LNG facility in terms of the size and scope of the proposed facility; and to b) discuss the Department's requirements for additional information on the facility that addresses the issues raised in section II.M.2. of the Department Analysis.

5. No later than March 1, 2002, and annually thereafter, the Company shall file an Affiliate Transaction report as described in Section II.P. Unregulated Affiliates for review by the Department.

6. No later than March 1, 2002, the Company shall file a report on the Willimantic remediation effort.

7. No later than July 1, 2002, Yankee file a report on the possibility of using tax-exempt financing for its coal-tar remediation efforts.

8. No later than March 1, 2002, Yankee shall develop and file a written plan for making customer complaints a service quality component.

9. No later than March 1, 2002, Yankee shall develop and file for approval a Customer Satisfaction Survey as a service quality measure component of the SQP.

10. No later than March 1, 2002, Yankee shall develop and file a written plan for tracking abandoned telephone calls and for including abandoned calls when calculating the ASA SQP.

11. No later than March 1, 2002, Yankee shall file its Termination Notice and envelope that entails 'Urgent Notice Enclosed' in bold print to alert customers. The Termination Notice shall also reflect the correct amount of time allowed paying the bill.

12. No later than March 1, 2002, Yankee shall file each month a report on the percentage and number of actual meter reads, as compared to the total number of meter reads.

13. No later than March 15, 2002, Yankee inform the Department that it maintains supporting information for their budgeted accounts in a centralized location to provide for ease of auditing.

14. No later than August 1, 2002, and annually thereafter, the Company shall file

its proposal for IERM projects to be placed in-service during the upcoming rate year as discussed in Section II.I. System Expansion.

15. No later than August 1, 2002 and annually thereafter, the Company shall file information on the performance of IERM projects placed in-service prior to the filing as discussed in Section II.I. System Expansion.

16. No later than December 31, 2002 and annually thereafter, Yankee shall return any earnings through the ESM to both firm sales and transportation customers through a line item on each class of customer's individual bill. Thereafter, Yankee shall file a report within 30 days indicating the total amount of earnings returned, date returned and calculation of credits to each customer.

17. No later than January 31, 2003, and annually thereafter, Yankee shall provide a report showing all merger synergy savings for the preceding calendar year.

18. No later than February 15, 2003 and annually thereafter, the Company shall file a suspected gas leak call responsiveness report together with all supporting documentation and workpapers showing all calculations. Said filing shall be in addition to the routine monthly filings made to the GPSU.

19. No later than February 15, 2003 and annually thereafter, the Company shall file its third party damage report covering the 12-month period of the SQP, plus the previous 12-month period. The data shall show damages and notifications by month, and contain any additional supporting documentation, work papers and calculations. In addition, the Company shall file this data monthly with the GPSU that it will review as part of its routine review of the safety operations of the Company.

20. No later than March 31, 2003 and annually thereafter, the Company shall file an annual report that indicates, by individual customer, ILEP original costs and amortization to date, annual margin, margin contribution allocated to costs and rate of return, and excess margin sharing between ratepayers and shareholders.

21. The Company shall add the language as stated in Section II.N.2. Meter Set Installations to the Company's Rules and Regulations when it is filed in the rate design phase of this rate case.

22. Yankee shall reduce the proposed 45-second ASA to 30 seconds for 2002 and by 5% annually thereafter.

23. Yankee shall file a report whenever the ASA exceeds the 30-second benchmark in any given month.

24. Yankee shall implement a Service Call Responsiveness Benchmark of 85% for meeting service appointments within a two-hour window in year 2002 and improve by 1.5% annually thereafter.

25. The Company shall file a report on any service quality measure that failed to meet its benchmark in any month and include a remedial plan to bring the performance measure up to the benchmark.

26. Yankee shall file any changes to its billing format, customer service policies and procedures, Rules and Regulations, at least 10 business days prior to implementation.

27. The Company shall book all expenses associated with the Fuel Diversity Fund and associated marketing costs below the line and not include any fund-related costs in O&M expenses or in rates.

28. All of Yankee's reports filed with the Department regarding its coal-tar remediation activities, including annual reports and rate-case and financial-review presentations, shall specifically address the Company's role in those activities, and in restraining their costs.

29. The Company shall account separately for coal-tar remediation expenses incurred in the development of the Waterbury site for the proposed LNG facility. Coal-tar remediation expenses at that site shall be recovered pursuant to the provisions of the order governing those expenses.

30. The Company shall compute the proposed IERM in accordance with the discussion in Section II.I. System Expansion.

31. The Company shall submit a proposal for a special contract for any potential

ILEP project with an investment above 1.25% that contains the information listed in Section II.J. Interruptible Line Extension Policy.

32. The Company shall meet with the GPSU, as part of its on-going routine activities, to determine what further studies of the LNG facility and possible impoundment areas need to be performed and what the final design should be in terms of the issues raised in section II.M.3. LNG Plant Safety

33. The propane storage tanks at the Waterbury facility shall be deactivated and purged of propane prior to LNG being introduced into the LNG storage tank and no propane may be stored in the tanks while the LNG storage tank remains in service (i.e., contains LNG).

34. The LNG plant shall be staffed onsite, 24 hours per day, every day, by dedicated, competent, qualified and fully trained, LNG plant operators whenever LNG is present at the facility.

35. The final engineering designs for the LNG plant must receive final approval from the GPSU before commencement of construction.

36. Operations, maintenance and emergency procedures must be approved by the GPSU prior to LNG being introduced into the LNG storage tank.

37. The Company shall continue filing the annual coal tar remediation report as described in Section II.D.8. Environmental Remediation of the Decision dated August 26, 1992 in Docket No. 92-02-19.

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Glenn Arthur DISSENTING OPINION

103-110] I must dissent from the majority's decision on two issues. Specifically, I disagree with 1) allowing Yankee Gas Services Company (Yankee or Company) to implement a ratepayer-subsidized Infrastructure Expansion Rate Mechanism (IERM) subject to the Department of Public Utility Control's (Department) future review and approval; and 2) allowing a regressive earning sharing mechanism (ESM). There are both legal and public policy issues that raise the following concerns.

I. INFRASTRUCTURE EXPANSION RATE MECHANISM

A. Legal Issues

The IERM allows the Company to seek a reopening of this rate case for the sole purpose of obtaining rate recovery for capital additions alone, to the exclusion of other costs or revenues that may have increased or decreased. The IERM, as approved, violates the prohibition against single-issue ratemaking. This prohibition is a hallmark of one hundred years of ratemaking, and a fundamental requirement for determining just and reasonable rates. Without considering all of the other changes in the revenues and costs, it is impossible to find that any rate is just and reasonable in accordance with § 16-19e of the General Statutes of Connecticut (Conn. Gen. Stat.). Business and Professional People for the Public Interest v. Illinois Commerce Commission, 585 N.E.2d 1032 (1991); State ex rel. Utility Consumers Council of Missouri, et al v. Missouri Public Service Commission of Missouri, 585 S.W.2d 41 (1979).

I do not believe that a policy design encouraging system expansion can cure this fatal legal flaw. Because the IERM allows rates to track capital additions alone, I believe the mechanism is essentially an automatic capital addition adjustment clause. This Department is not authorized to create such adjustment clauses. Adjustment clauses and other exceptions to the rule can only be created by the General Assembly. Wisconsin's Environmental Decade, Inc. v. Public Service Commission, 260 N.W.2d 712 (1978). One statute creates the fuel and purchased gas adjustment clauses. In addition, this statute, Conn. Gen. Stat. §16-19b(a), expressly prohibits other clauses. 'No adjustment clause of any kind whatsoever shall be authorized by the Department of the Public Utility Control if such clause operates automatically ...'(emphasis added)'. Yet the Department approves this automatic capital adjustment clause in this decision.

A. B. PUBLIC POLICY ISSUES

Aside from the legal issues aforementioned, the Company's IERM is flawed for the following public policy reasons.

. it imposes costs on current ratepayers to build plant to provide services to customers who may or may not ever seek service;

. it approves plant investments in rate base without asking whether the investments will ever be 'used and useful;' and

. the Department fails to use traditional regulatory investment review standards such as whether the investment has a positive net present value and a normal investment's internal rate of return;

The use of the ratepayers' portion of the ESM to pay for the Company's capital cost is unprecedented and unjustifiable. In this Decision, if the ratepayer's portion of the ESM does not cover the capital cost of the IERM projects, the Company can place a surcharge on ratepayer bills to make up for the loss. [FN1] Meanwhile, as ratepayers take the risk of investing in these capital additions, shareholders go along happily earning the allowed 11% return on investment plus a share of any profits generated with ratepayer's dollars. Further, the Department made no risk adjustment to the Company-allowed ROE to reflect the significant transfer of risk from shareholders to ratepayers. The Department did adjust for not including a Weather Normalization Adjustment (WNA). I believe that the adoption of the IERM, without adjusting other revenues, expenses and the Company's allowed return on investment to account for ratepayer prepaying for those investments is patently unfair.

II. EARNING SHARING MECHANISM

Unlike the regressive ESM that was adopted in the final Decision, a progressive ESM encourages more rapid efficiency improvements. Encouraging more rapid efficiency improvements makes common sense and good public policy. Giving the Company the 'big rewards,' that is, a larger percentage of earnings greater than the established ROE upfront, does not incent nearly as much as giving the 'big rewards' when overearnings are more difficult to achieve.

In addition, the ESM is structured such that all Company earnings above its allowed ROE of 11% results in money used by the Company free of charge each year. Residential customers pay more for service than they should. This results in less money they can save or spend in the economy. Similarly, commercial and industrial customers suffer from higher energy costs of doing business that reduces their products' competitiveness in the open market. Further more, money the Company collects above its allowed ROE is not available for investment by individual private companies.

Yankee has been given the opportunity to earn a generous 11% ROE. If it does not earn the allowed 11%, it can always petition the Department to increase rates. Given the current state of the economy with unemployment rising and companies reporting negative earnings or even going bankrupt, Yankee can still earn an 11% profit for the next four to five years. Simply put, today's economic climate is grossly out of sync with the economics of the Company's potential overearnings. The regressiveness of the ESM further exacerbates this stark inconsistency.

The interrelationship of the IERM and the ESM is a curious one. First, the regressive ESM distributes to shareholders a disproportionate share of overearnings relative to ratepayers' share. Adding insult to injury, the ratepayers' share of overearnings are diverted to support the net costs of IERM projects. Because those projects fail certain economic viability tests, they are sure to place a financial burden on existing ratepayers. Ironically, then, the ESM does not credit ratepayers for the cost savings that drive overearnings; instead, those cost savings are forcibly transformed into a cost increase to ratepayers by the IERM. This is a misguided result.

III. SUMMARY

The IERM adopted in the final Decision violates the prohibition against single issue ratemaking, and is a significant legal flaw.

Ratemaking principles are based upon a utility's being allowed to earn a reasonable rate of return in exchange for providing efficient and adequate service. The Company has failed to prove that the IERM projects will provide efficient service, and that the IERM's funding through the ESM provides Yankee with an 'exorbitant ROE rather than a reasonable one'.

Finally, a sound performance based ratemaking plan should contain a progressive ESM that provides the appropriate incentives.

For these reasons, I respectfully dissent.

Glenn Arthur, Commissioner Date: February 8, 2002

FOOTNOTES

Decision

FN1 NOAA is the source of the Bradley Field data. Response to Interrogatory GA-342.

FN2 Decision dated May 25, 2000, in Docket No, 99-09-03, Application of Connecticut Natural Gas Corporation for a Rate Increase -- Phase I; Decision Dated January 25, 2000, in Docket No. 99-04-18, DPUC Review of The Southern Connecticut Gas Company Rates and Charges -- Phase II.

FN3 The Department notes that while Conn. Gen. Stat. § 16-19d does contain an exception for a gas company to recover reasonable expenses incurred in the promotion or marketing of efficient gas equipment, the Company did not make the demonstrations required pursuant to Regulations of Connecticut State Agencies Section 16-19d-1. et seq..

FN4 The Company's plan is to increase its employee count from 408 to 508.

FN5 The proposed rate year payroll expense is \$27,477,000 + \$15,327,000 -- \$18,192,000 = \$24,612,000.

FN6 OCC used five-year historical data from 1995 through 1999, while the Department's analysis below used five-year historical data from 1996 through 2000.

FN7 Yankee PFT Schedule C-3.19a, Line 28, \$5,335,000 is multiplied by .5136 to get the adjustment of \$2,741,000. Line 29 is the adjusted Line 28 multiplied by 4% to calculate an escalation reduction of \$109,600. Capitalized labor expenses are taken out of the payroll expense; therefore \$439,250 is an adjustment addition. The Department used a five-year average of 84.56% ratio of capitalized labor to payroll in calculating this adjustment.

FN8 Payroll expense adjustment of \$2,741,000 is multiplied by 8.3% to derive \$227,500.

FN9 $(11.39\% + 12.16\%) / 2 = 11.78\%$.

FN10 Yield adjustment = $(0.5 \times 6.32\%) \times 4.84\% = 0.15\%$.

FN11 DCF cost of equity = $4.84\% + 6.32\% + 0.15\% + 0.08\% = 11.39\%$.

FN12 Because First Call did not have an earnings projection for CGC, analyst estimates available from Zacks reports, also dated June 25, 2001, were used for this company.

FN13 In Mr. Hill's PFT, the average sustainable growth rate of 5.65% was for his group of seven companies. The average growth rate in this table is for the nine companies in Mr. McHale's proxy group.

FN14 $4.85\% \times (1 + (0.5 \times 5.91\%)) = 5.0\%$.

FN15 The hurdle rate is a calculation used by the Company to determine if a customer's contribution to a given project is necessary.

FN16 Penetration is the number of customers along any given mile of distribution main.

FN17 Projects that fail to achieve a positive IRR because of reliability costs may be considered pursuant to the IERM under the conditions discussed in Section II.4. System Expansion and Reliability below.

FN18 Including incremental administrative costs; O&M overhead and maintenance costs; depreciation costs; associated taxes; and all other incremental costs associated with the project.

Dissent

FN1 Put differently, the IERM awards the Company annual rate increases for its system expansion, in the form of a surcharge on ratepayers' bills, unless the ratepayers' share of overearnings covers the rate adjustment.

EDITOR'S APPENDIX

PUR Citations in Text

CONN.] Re Connecticut Light & Power Co., 90 PUR4th 148, Docket No. 87-07- 01, Feb. 4, 1988.

CONN.] Re Connecticut Nat. Gas Co., 201 PUR4th 225, Docket No. 99-09-03, May 25, 2000.

CONN.] Re Connecticut Nat. Gas Co., 210 PUR4th 27, Docket No. 99-09-03, May 9, 2001.

CONN.] Re Consolidated Edison, Inc., 205 PUR4th 182, Docket No. 00-01-11, Oct. 19, 2000.

CONN.] Re Performance-Based Regulation for Electric Distribution Companies, 199 PUR4th 48, Docket No. 99-06-21, Feb. 2, 2000.

CONN.] Re Review of Nat. Gas Companies Cost of Service Study Methodologies, 202 PUR4th 421, Docket No. 99-03-28, Aug. 9, 2000.

CONN.] Re Southern Connecticut Gas Co., 198 PUR4th 233, Docket No. 99-04- 18, Jan. 28, 2000.

MO.Sup.Ct.] State of Missouri ex rel. Utility Consumers' of Missouri Inc. v. Missouri Pub. Service Commission, 33 PUR4th 273, 585 S.W.2d 41 (1979).

U.S.Sup.Ct.] Federal Power Commission v. Hope Nat. Gas Co., 51 PUR(NS) 193, 320 U.S. 591, 88 L.Ed.2d 333, 64 S.Ct. 281 (1944).

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