IN THE TENNESSEE REGULATORY AUTHORITY
NASHVILLE, TENNESSEE

IN RE: UNITED CITIES GAS COMPANY, a Division of ATMOS ENERGY CORPORATION INCENTIVE PLAN (IPA) AUDIT UNITED CITIES GAS COMPANY, a Division of ATMOS ENERGY CORPORATION, PETITION TO AMEND THE PERFORMANCE BASED RATEMAKING MECHANISM RIDER	)	Consolidated Docket Nos. 01-00704 and 02-00850

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RESPONSE OF ATMOS ENERGY CORPORATION TO THE ATTORNEY GENERAL'S WRITTEN DISCOVERY

Atmos Energy Corporation ("Atmos" or "the Company") provides this Response to the Written Discovery served by the Tennessee Office of the Attorney General, Consumer Advocate and Protection Division ("CAPD").

I. **INTERROGATORIES**

1. State each fact you rely on to support your contention that the amendment to the AEC PBR proposed in TRA Docket No. 02-00850 should be approved by the TRA.

RESPONSE: The facts supporting the Company's contention that the amendment should be approved are recited in the order and tariffs in the original PBR docket (Docket No. 97-01364) and all documents filed by the Company in Docket Nos. 01-00704 and 02-00850.

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2. Identify all persons known to you, your attorney, or other agent who have knowledge, information or possess any document(s) or claim to have knowledge, information or possess any document(s) which support your answer to Interrogatory number one (1) above.

RESPONSE: Undersigned counsel, Randal Gilliam, Hal Novak, Pat Murphy, Patricia Childers, John Hack, Frank Creamer.

3. Identify each document, photograph, or any other article or thing whatsoever, which you claim to corroborate any part of your contentions, position or belief that the amendment to the AEC PBR proposed in TRA Docket No. 02-00850 should be approved by the TRA, whether as to the issues of credibility or any other issue, or which is adverse to your contentions, position or belief that the amendment to the AEC PBR proposed in TRA Docket No. 02-00850 should be approved by the TRA, whether as to the issues of credibility or any other issue.

RESPONSE: See the transportation contracts at issue, the order and tariffs in the original PBR docket (Docket No. 97-01364) and all documents filed by the Company in Docket Nos. 01-00704 and 02-00850. The Company is unaware of any "document, photograph, or any other article or thing whatsoever" which is adverse to its position that the proposed amendment should be approved.

4. With respect to each person you expect to call as an expert witness, or provide any form of testimony from, regarding this matter, state:

a. their full name and work address;

b. each subject matter about which such witness is expected to testify;

c. the substance of the facts and opinions to which the expert is expected to testify;

d. a summary of the grounds or basis of each opinion to which such witness is expected to testify; and

e. whether or not the expert has prepared a report, letter of memorandum of his findings, conclusions or opinions.

RESPONSE: Atmos intends to call Pat Childers, John Hack, and Frank Creamer to provide direct testimony in this matter. Atmos' answers to the remaining questions in this interrogatory are contained in the pre-filed direct testimony of those individuals. No reports or letters of memorandum have been prepared other than the filings made in this matter.

5. Identify each state where the incentive program set out in the amendment to the AEC PBR proposed in TRA Docket No. 02-00850 has been approved, by state and docket or matter number. Provide copies of the documents and things filed in each.

RESPONSE: Atmos is not aware of the details of incentive programs governing other companies. Atmos has an incentive program in Kentucky similar to the program set forth in the proposed tariff (Western Kentucky Gas PBR Order attached). LG&E also has a similar order in Kentucky. (LG&E Order - Kentucky Public Service Commission Docket No. 2001-00317 (attached).

6. Explain in detail the extent to which FERC Order: Modification of Negotiated Rate Policy, Natural Gas Pipeline Negotiated Rate Polices and Practices, 104 FERC ¶ 61,134 (2003) is or is not relevant to the question of whether the amendment to the AEC PBR proposed in TRA Docket No. 02-00850 should be approved by the TRA.

RESPONSE: It is the Company's position that the referenced FERC Order is not relevant to the question of whether the amendment proposed in Docket No. 02-00850 should be approved. The 2003 FERC order does not reverse FERC's negotiated rate policy, but actually

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does just the opposite - the 2003 order reaffirms the policy's effectiveness and specifically rejects one industry commentator's suggestion to eliminate the negotiated rate policy altogether. (FERC Order at ¶¶ 10, 4) (stating that "[t]he Commission finds that its negotiated rate program has been generally successful in providing flexible, efficient pricing of pipeline capacity while mitigating pipeline use of market power by means of a recourse rate.") What the 2003 order does do is find a potential for pipeline manipulation under one very specific type of pricing mechanism - basis differential pricing - and disallow that particular pricing mechanism. (FERC Order ¶ 16, stating that "[t]he Commission has determined to modify its negotiated rates policy and will no longer permit the use of gas basis differentials to price negotiated rate transactions.")[1] Basis differential pricing is the practice of pricing transportation services based on the difference between the commodity gas price at two different points. (FERC Order ¶ 16.) None of Atmos' discounted transportation contracts employ the basis differential pricing mechanism. (See Aff. of R. McDowell, previously filed in this matter, ¶ 4.) Therefore, the manipulation risk the FERC was concerned about and discussed in the order simply does not exist for Atmos' discounted contracts. As such, the 2003 FERC Order has no relevance whatsoever to the issue of whether Atmos should be able to share in savings resulting from discounted transportation contracts.

7. What financial concessions did AEC provide to the pipelines that reached negotiated transportation agreements with AEC?

RESPONSE: None.

8. How much compensation is being provided to Mr. Frank Creamer in relation to testimony, exhibits, or other consulting work for AEC?

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[1] See also, FERC Order Dissent of Commissioner Brownell, ¶1, stating that "[I]n this order, the majority prohibits on a prospective basis the use of gas basis differentials to price negotiated rate transactions."

RESPONSE: Atmos objects to this interrogatory in that it is not limited to any particular period of time. Without waiving that objection, Mr. Creamer's total fees for all Atmos entities from April 2000 through the date of this filing total $42,672.

9. Identify all employees of AEC and affiliates who have received or will receive compensation associated with PBR plan results. How much compensation was and will be provided to each of these employees for the years 1999, 2000, 2001, 2002, 2003 and 2004? Will the compensation to any of these individuals be reduced should AEC not prevail in TRA Dockets 01-00704 and 02-00850?

RESPONSE: ~~No Atmos employees receive compensation~~ associated with PBR plan results.

10. Identify all AEC and affiliate personnel or agents who are involved in gas purchasing or transportation decisions and the duties of each employee and/or agent. Provide the salaries, bonuses, and any other compensation provided to each of these and identify how much of this compensation is allocated to Tennessee expenses or investments.

RESPONSE: Because the response to this interrogatory contains confidential information protected under Tennessee law, it has been filed under seal.

11. Lines 164-166 of Mr. Creamer's testimony, filed July 30, 2004, describe how "Atmos could increase its savings on the commodity portion, which it would share in, by entering into relatively high transportation cost arrangements (which would be passed on to the ratepayer) in order to lower commodity costs." Explain in detail how AEC could do this? Who would provide the transportation? Who would provide the gas? How would the gas provider recover losses from the transportation provider? If AEC could make money doing this, has this already been done? Does AEC intend to pursue the path outlined by Mr. Creamer?

RESPONSE: Atmos could purchase transportation services from a pipeline company and the commodity from that pipeline company's affiliate The pipeline company may charge "full price" for a service that it might otherwise discount, and have the affiliate offer a discount off the commodity to secure the deal. This "pass-through" of the implied transportation discount to the affiliate's commodity charge to Atmos would be captured as a benefit in the PBR plan, if transportation costs were excluded. Atmos has not to date entered into such transactions. In the future, Atmos intends to follow the guidelines set forth in its PBR tariff, however those guidelines are interpreted or amended by this consolidated docket. Because the appropriate treatment of transportation costs will not be determined until the resolution of this consolidated docket, Atmos is without sufficient information to provide further speculation as to possible future actions.

12. Has AEC or affiliates made gas purchases similar to those illustrated in "Option 1" of Attachment A to Mr. McCormac's testimony, filed July 30, 2004, in which the total delivered cost at the "Maximum FERC Rate" would be greater than the cost of gas that could have been purchased at the city gate? Provide details of all such purchases and explain the reasoning behind these purchases.

RESPONSE: Atmos is unaware of any purchases fitting the specifications outlined in Mr. McCormac's hypothetical. As noted in paragraph 5 of the Affidavit of Ron McDowell, previously filed in this matter, Mr. McCormac's hypothetical is overly simplistic and does not reflect the realities of the Company's gas supply purchases. The hypothetical ignores additional considerations the Company must take into account in making purchasing decisions, including operational, reliability, and safety concerns. Purchases without a separate transportation component like the "Murfreesboro" example cited in Mr. McCormac's affidavit are not generally backed by primary firm transportation and may not be available on critical days. In order to meet its service obligations, the Company follows a general practice of subscribing to primary firm transportation. Differences in reliability requirements directly impact pricing for transportation services. Mr. McCormac did not specify the service obligations of the two delivery hypotheticals; however, in order for the Murfreesboro example to be the low price option, the service obligation must be interruptible. Consequently, Mr. McCormac is making an apples to oranges comparison that does not take into consideration the reality of the working gas market.

13. Does Mr. Creamer's approach to quantifying "transportation savings," an approach he describes in his July 30 testimony from page 13 to 20, result in "transportation savings" identical in amount to the "transportation savings" which the TRA staff discovered in its audit of the AEC in Docket 01-00704? If not, provide the "transportation savings" Mr. Creamer's approach would provide if his approach were applied to the current PBR plan, and provide the "transportation savings" Mr. Creamer's approach would provide if his approach were applied to the new PBR plan proposed on Docket 02-00850.

RESPONSE: No, the approach Mr. Creamer describes in his July 30 pre-filed direct testimony (the "Creamer Approach") does not result in transportation savings identical in amount to the transportation savings Atmos calculated in its annual filing for the audit at issue in Docket No. 01-00704. Atmos has not made complete calculations using the Creamer Approach for the entire audit year, but attached is a chart of calculations for June 2000, November 2000, and March 2001. Using those calculations as a guide, the total savings Atmos would be entitled to for the audit year under the Creamer Approach would be approximately $111,867 less than the savings as filed in the Company's annual filing for the audit year. Atmos has not made quarterly of annual filings for any year since the audit year. Atmos objects to the portion of this interrogatory requesting a calculation of the transportation savings the Creamer Approach would provide if applied to the PBR plan proposed in Docket No. 02-00850. The PBR plan proposed in Docket No. 02-00850 specifies a method of calculation that is separate and distinct from the Creamer Approach. Therefore, it is impossible to apply the Creamer Approach to the new PBR plan proposed in Docket No. 02-00850.

14. Describe in detail how the FERC's maximum transportation price is set.

RESPONSE: The maximum FERC rate on any given pipeline is set through the FERC ratemaking process. The FERC ratemaking process can be separated into five distinct steps:

1. Determine the overall costs that should be recovered in the rates;
2. Separate the "test period cost of service" into pipeline functions such as gathering, transmission, and storage;
3. Classify "functionalized" costs into demand and commodity components;
4. Allocate demand and commodity components among pipeline company service; and
5. Design unit rates.

Rates are also designed to reflect the pipeline company's quality of service. Therefore, interruptible rates are usually one-part rates that are generally lower and include only a small portion of the demand cost.

FERC can also influence the ratemaking process to achieve policy goals that are pertinent to prevailing market conditions. To achieve policy goals, FERC uses the cost classification aspect of the ratemaking process to classify fixed costs and either demand or commodity or some mixture of the two.

15. If your response to any Request for Admission is other than an unqualified admission, state for each such Request for Admission the following:

a. all facts that you contend support in any manner your response to the extent it is not a complete admission;

b. for any information you contend is incorrect or inaccurate provide the correct information;

c. identify all documents, or any tangible or intangible thing that supports in any manner your lack of admission or your qualification of your admission;

d. the name and address of the custodian of all tangible things identified in response to subsection (b) of this interrogatory; and

e. the name and address of all persons, including consultants, purporting to have any knowledge or factual data upon which you base your lack of admission or your qualification of your admission.

RESPONSE: Atmos' response to this interrogatory is included in the admission responses below. For Atmos' response to subsection (e) above, see the Company's response to Interrogatory No. 2.

II. REQUESTS FOR THE PRODUCTION OF DOCUMENTS AND THINGS

1. Any and all documents identified in your answers or responses to these Interrogatories.

RESPONSE: Attached.

2. Any and all documents reviewed to prepare your answers or responses to these Interrogatories.

RESPONSE: The Company objects to this request on the grounds that the request is vague, overbroad, unduly burdensome and seeks information which is irrelevant and not reasonably calculated to lead to the discovery of admissible evidence.

3. Any and all expert reports which have been obtained from any expert.

RESPONSE: Other than the documents filed in this matter, Atmos has not obtained any expert reports related to this matter.

4. Each document, photograph, or any other article or thing whatsoever, upon which you rely in support of your contention(s), position(s) or belief(s) that the amendment to the AEC PBR proposed in TRA Docket No. 02-00850 should be approved by the TRA.

RESPONSE: See the Company's response to Interrogatory No. 3 above. All of the identified documents have previously been provided to the CAPD.

5. Provide copies of emails, notes, reports, or studies which are authored before January 31, 2001 by any AEC employee(s), expert(s), or consultant(s) and which refer to FERC's maximum transportation price.

RESPONSE: Atmos objects to this request on the grounds the request is vague, overbroad, unduly burdensome and seeks information which is irrelevant and not reasonably calculated to lead to the discovery of admissible evidence. Without waiving that objection, Atmos has made a reasonable search of its records and the only documents it discovered responsive to this request are the Company's ACA and PGA filings and quarterly and annual PBR reports, copies of which have previously been provided to the CAPD.

6. Produce all documents and things used by AEC or affiliates used [sic] to make prudent purchasing and transportation decisions for 1999 through 2003.

RESPONSE: Atmos objects to this request on the grounds the request is vague, overbroad, unduly burdensome and seeks information which is irrelevant and not reasonably calculated to lead to the discovery of admissible evidence. Without waiving that objection, for the documents Atmos used to make prudent transportation decisions for the specified time period, see the discounted transportation contracts at issue in this matter; and the Company's PBR plan and quarterly and annual PBR filings.

7. Produce all documents and things used to determine the quality of gas purchased from NORA.

RESPONSE: Gas purchased from NORA comes through the East Tennessee Natural Gas, LLC system and must conform to the quality specifications for that system, a copy of which is attached.

III. REQUESTS FOR ADMISSION

1. A published index for transportation costs does not currently exist.

RESPONSE: Admitted. As noted on page 11, line 249 of Mr. Creamer's pre-filed direct testimony, a published index for transportation costs does not currently exist. However the absence of a published index for transportation costs do not prevent the use of published FERC rates as the benchmark of performance for the market place as noted in pages 11-20 of Mr. Creamer's pre-filed testimony.

2. AEC knew in 2001 that a published index for transportation costs did not exist.

RESPONSE: Admitted.

3. AEC knew in 2000 that a published index for transportation costs did not exist.

RESPONSE: Admitted.

4. AEC knew in 1999 that a published index for transportation costs did not exist.

RESPONSE: Admitted.

5. AEC knew in 1998 that a published index for transportation costs did not exist.

RESPONSE: Admitted.

6. AEC knew in 1997 that a published index for transportation costs did not exist.

RESPONSE: Admitted.

7. AEC knew in 1996 that a published index for transportation costs did not exist.

RESPONSE: Admitted.

8. AEC knew in 1995 that a published index for transportation costs did not exist.

RESPONSE: Admitted.

9. Before the January 31, 2001 meeting with the TRA Staff, AEC had not prepared memoranda, emails, notes, reports, studies or other documents which refer to FERC's maximum transportation price.

RESPONSE: Denied. See Atmos' response to Interrogatory No 5 above.

10. Pages 13-20 of Frank Creamer's testimony, filed July 30, 2004, provides an example of Mr. Creamer's opinion on "how transportation costs savings should be calculated for a particular month under the current PBR plan." Admit that his "current" plan and its

formulas have not previously been discussed in any record before the TRA, outside TRA Dockets 01-00704 and 02-00850.

RESPONSE: Denied. Transportation costs are a feature of the current plan. The NORA contract is one such example. See the order and tariffs in the original PBR docket (Docket No. 97-01364) and all documents filed by the Company in Docket Nos. 01-00704, 02-00850, and 00-00844.

11. The amount of $.3522, shown under the column titled "Index ($/MMBTU)" in the table included in paragraph 21 of Mr. Creamer's affidavit of October 21, 2002, is not an index.

RESPONSE: Denied. While the FERC maximum rate is not a published index, it is an index which serves as the benchmark of performance as outlined in Mr. Creamer's pre-filed direct testimony at pages 11-13.

12. The amount of $.3522 is at least six times larger than the transportation costs of "5 ½ cents" identified in the transcript of Docket No. 97-01364, Volume III page 799, line 20.

RESPONSE: Atmos admits that the amount of $.3522 is approximately 6 times larger than the amount of 5 ½ cents. All futher allegations contained in this request are denied. The referred to costs are two separate cost categories. The amount of 5 ½ cents is a variable commodity cost. The amount of $.3522 is the demand rate divided by number of days (30.4).

13. The term "Bundled Index," shown under the column titled "Category" in the table included in paragraph 21 of Mr. Creamer's affidavit filed October 21, 2002, does not appear in the record of Docket No. 97-01364.

RESPONSE: Atmos admits that the term "Bundled Index" does not appear in the record of Docket No. 97-01364. However, the concept of a bundled index is contained in the current PBR plan. The NORA contract and other city gate purchases are two such examples, as noted on page 6 of Mr. Creamer's pre-filed direct testimony.

14. The term "Bundled Index," shown under the column titled "Category" in the table included in paragraph 21 of Mr. Creamer's affidavit filed October 21, 2002, is the first instance of "Bundled Index" being used in Docket No. 01-00704

RESPONSE: Atmos admits that Mr. Creamer's affidavit filed October 21, 2002 is the first instance of the term "Bundled Index" being used in Docket No. 01-00704. However, the concept of a bundled index is contained in the current PBR plan. The NORA contract and other city gate purchases are two such examples, as noted on page 6 of Mr. Creamer's pre-filed direct testimony.

15. AEC is unable to identify any financial incentive for the pipelines to provide transportation services to AEC at prices below the FERC maximum rate.

RESPONSE: Denied. The financial incentive for the pipelines is keeping Atmos as a customer.

17. Any market index for the pricing of transportation services would be less than the FERC maximum rate.

RESPONSE: Denied. As noted on pages 11-13 of Mr. Creamer's pre-filed direct testimony, the FERC maximum rate is the appropriate benchmark of performance and serves as the index against which Atmos' performance would be measured.

18. AEC intends to invite pipeline companies to end their discount-pricing transportation services being provided to AEC if the TIF tariff is denied by the TRA.

RESPONSE: In the future, Atmos intends to follow the guidelines set forth in its PBR tariff, however those guidelines are interpreted or amended by this consolidated docket. Because the appropriate treatment of transportation costs will not be determined until the resolution of this consolidated docket, Atmos is without sufficient information to admit or deny this request.

19. AEC intends to voluntarily increase its payments for discount-price transportation services being provided to AEC if the TIF tariff is denied by the TRA.

RESPONSE: In the future, Atmos intends to follow the guidelines set forth in its PBR tariff, however those guidelines are interpreted or amended by this consolidated docket. Because the appropriate treatment of transportation costs will not be determined until the resolution of this consolidated docket, Atmos is without sufficient information to admit or deny this request.

20. The transportation prices paid by AEC in the past are not a market index.

RESPONSE: Atmos admits that the transportation prices paid by Atmos as a whole do not constitute a market index. As noted on pages 11-13 of Mr. Creamer's pre-filed direct testimony, the FERC maximum rate is the appropriate benchmark to serve as the index against which Atmos' performance should be measured.

21. AEC took no risk to get pipelines to discount their prices for transportation services provided to AEC.

RESPONSE: Denied. Atmos risked losing any return on its expenditure of resources necessary to procure the discounted contracts.

22. The East Tennessee Pipeline is an upstream pipeline for AEC in Tennessee.

RESPONSE: Atmos objects to this request as vague in that the term "upstream pipeline" is not defined. On pages 11-13 of his pre-filed direct testimony, Mr. Creamer refers to upstream transportation costs (i.e., the transportation costs to get the gas from the well head to the pipeline receipt point) and downstream transportation costs (i.e., the cost of transporting the gas from the receipt point to the city gate). Atmos is unable to ascertain the meaning of the terms "upstream pipeline" or "downstream pipeline" as used in this request.

23. The East Tennessee Pipeline is a downstream pipeline for AEC in Tennessee.

RESPONSE: See response to Request for Admission No. 22 above.

24. The Tennessee Pipeline is an upstream pipeline for AEC in Tennessee.

RESPONSE: See response to Request for Admission No. 22 above.

25. The Tennessee Pipeline is a downstream pipeline for AEC in Tennessee.

RESPONSE: See response to Request for Admission No. 22 above.

26. The Texas Eastern Pipeline is an upstream pipeline for AEC in Tennessee.

RESPONSE: See response to Request for Admission No. 22 above.

27. The Texas Eastern Pipeline is a downstream pipeline for AEC in Tennessee.

RESPONSE: See response to Request for Admission No. 22 above.

28. The Southern Natural Gas Pipeline is an upstream pipeline for AEC in Tennessee.

RESPONSE: See response to Request for Admission No. 22 above.

29. The Southern Natural Gas Pipeline is a downstream pipeline for AEC in Tennessee.

RESPONSE: See response to Request for Admission No. 22 above.

30. The NORA Pipeline is an upstream pipeline for AEC in Tennessee.

RESPONSE: See response to Request for Admission No. 22 above.

31. The NORA Pipeline is a downstream pipeline for AEC in Tennessee.

RESPONSE: See response to Request for Admission No. 22 above.

32. The Columbia Gulf Pipeline is an upstream pipeline for AEC in Tennessee.

RESPONSE: See response to Request for Admission No. 22 above.

33. The Columbia Gulf Pipeline is a downstream pipeline for AEC in Tennessee.

RESPONSE: See response to Request for Admission No. 22 above.

34. The FERC currently develops a maximum annual transportation rate for each pipeline that, when applied to the pipeline's contract demand and throughput levels, will enable the pipeline to recover its annual cost-of-service requirement.

RESPONSE: Atmos admits that the FERC currently develops a maximum transportation rate for each pipeline, and the intent is that, when applied to the pipeline's contract demand and throughput levels, the rate will provide the pipeline with an opportunity to recover its annual agreed-upon cost-of-service revenue requirement. All other allegations in this request are denied.

35. The FERC's maximum annual transportation rate for each pipeline is also known as the "FERC Maximum Rate."

RESPONSE: Atmos admits that the FERC's maximum transportation rate for each pipeline is also known as the "FERC Maximum Rate." Atmos is without sufficient information to admit or deny whether the rates are always set on an annual basis.

Respectfully submitted,

BAKER, DONELSON, BEARMAN
CALDWELL, & BERKOWITZ, P.C.

By: ______________________

Joe A. Conner, TN BPR # 12031
Misty Smith Kelley, TN BPR # 19450
1800 Republic Centre
633 Chestnut Street
Chattanooga, TN 37450-1800
(423) 752-4417
(423) 752-9527 (Facsimile)
jconner@bakerdonelson.com
mkelley@bakerdonelson.com
Attorneys for Atmos Energy Corporation

CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the foregoing has been served via U.S Mail, postage prepaid, upon the following this the 1st day of September, 2004:

Russell T. Perkins
Timothy C. Phillips
Office of the Attorney General
Consumer Advocate & Protection Division
P.O. Box 20207
Nashville, TN 37202

Randal L. Gilliam
Staff Counsel
Tennessee Regulatory Authority
460 James Robertson Parkway
Nashville, TN 37243

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VERIFICATION

I, Patricia J. Childers, hereby depose and say, after having been first duly sworn, that I have read the foregoing Interrogatories and the answers and responses thereto are true according to the best of my knowledge, information, and belief.

Patricia J. Childers

Name: Patricia J. Childers

Title: Vice President – Rates & Regulatory Affairs

STATE OF Tennessee)
)
COUNTY OF Williamson)

Personally appeared before me, Patricia J. Childers, with whom I am personally acquainted, and who acknowledged that he has answered the foregoing Interrogatories and executed the foregoing instrument for the purposes therein contained.

Witness my hand, at office, on this 30 day of August, 2004.

NOTARY PUBLIC

My Commission Expires: 9-25-04

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

MODIFICATION TO WESTERN KENTUCKY GAS COMPANY, A DIVISION OF ATMOS ENERGY CORPORATION, GAS COST ADJUSTMENT TO INCORPORATE AN EXPERIMENTAL PERFORMANCE BASED RATEMAKING MECHANISM (PBR)	)	CASE NO. 2001-00317

O R D E R

In Case No. 1997-00513, the Commission approved an experimental gas procurement performance-based rate-making mechanism ("PBR") for Western Kentucky Gas Company ("Western").[1] The experimental PBR, approved as a 3-year pilot, benchmarked all components of Western's gas cost and provided for a 50/50 sharing between ratepayers and shareholders of the amounts by which Western's gas costs varied from the benchmarks. The gas cost/gas procurement components contained in the PBR are: (1) Gas Acquisition Index Factor ("GAIF"); (2) Transportation Index Factor ("TIF"); and (3) Off-System Sales Index Factor ("OSSIF").

The GAIF includes Western's commodity costs, which are benchmarked based on the average of four indices, <u>Gas Daily</u>, <u>Natural Gas Week</u>, <u>Inside FERC</u>, and <u>NYMEX</u> closing prices. After the Commission approved the PBR mechanism, Western signed a full requirements gas supply contract with Noram Energy Services, Inc. and

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[1] Case No. 1997-00513, Modification to Western Kentucky Gas Company, A Division of Atmos Energy Corporation, Gas Cost Adjustment to Incorporate an Experimental Performance-Based Ratemaking Mechanism, Order dated June 1, 1998.

later entered into a similar agreement with Woodward Marketing, L.L.C. ("Woodward").[2] The contract excludes supply reservation fees and supplies gas to Western at a discount from the PBR benchmarks.

The TIF includes pipeline transportation costs, which are benchmarked against Western's pipeline suppliers' FERC-approved transportation rates. Western's pipeline suppliers are Texas Gas Company, Tennessee Gas Pipeline Company, Trunkline Gas, Midwestern and ANR Pipeline. The release of pipeline capacity ("capacity release"), which is a sub-part of the TIF component of the PBR, is an activity in which Western had engaged prior to the implementation of the PBR. Therefore, the experimental PBR contained a capacity release threshold that Western had to exceed before shareholders could participate in any savings realized through capacity release activities. During the pilot, Western established a commission-based sales program within its gas supply contract that paid a 10 percent commission for each dollar of capacity released.

The OSSIF reflects Western's net revenues, or savings, from off-system sales transactions. If revenues realized exceed the costs of such transactions, there are savings to be shared between ratepayers and shareholders. If costs exceed revenues, there are increased costs to be shared. Western did not use this mechanism during the pilot period. In order to increase the value of the contract to bidders, Western assigned the management of its storage and transportation assets to the supplier who retained the benefit of any off-system sales.

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[2] Case No. 1999-00447, A Formal Review of Western Kentucky Gas Company's Decision to Terminate a Natural Gas Sales, Transportation and Storage Agreement with Noram Energy Services, Inc. and Enter into a Natural Gas Sales, Transportation and Storage Agreement with Woodward Marketing, L.L.C.

As per the Order approving the pilot PBR, Western filed a report and testimony on the 3-year pilot on September 28, 2001.[3] For the pilot period, Western reported total savings realized under the PBR of $9 million. Because shareholders were not able to participate in any savings achieved as a result of capacity release activity, ratepayers retained $4.75 million of the total while shareholders received $4.25 million through Western's Gas Cost Adjustment Clause ("GCA").

A procedural schedule was established that provided for two rounds of discovery, intervenor testimony and rebuttal testimony. The Attorney General of the Commonwealth of Kentucky ("AG") is the only intervenor in this proceeding. A formal hearing was scheduled for February 19, 2002 but was cancelled by Order dated February 7, 2002, to allow Western and the AG to participate in settlement discussions. Commission Staff also participated in the discussions on a limited basis. On February 18, 2002, the parties filed a joint motion for approval of a Settlement Agreement ("Settlement") resolving, to their satisfaction, the issues in this case. The Settlement is attached as Appendix A.

The parties agree that the Settlement is for the purposes of this case only and shall not be binding on the parties in any other proceeding before this Commission or in any court and shall not be offered or relied upon in any other proceeding involving Western or any other utility regulated by this Commission.

The parties urge the Commission to review and accept the Settlement in its entirety as a reasonable resolution of the issues in this proceeding. While the overall reasonableness of the Settlement is an important factor, the Commission is bound by

[3] By Order dated October 22, 2001, Western was authorized to continue the PBR for 60 days after the Commission has entered its final order in this case.

law to act in the public interest and review all elements of the Settlement. In determining whether the results of the Settlement are in the public interest and beneficial to the ratepayers, the Commission considered the fact that the Settlement is a unanimous agreement of the parties.

After review of the Settlement, an examination of the record, and being otherwise sufficiently advised, the Commission finds that the Settlement is reasonable. The following is a synopsis of the terms of the Settlement:

1. The Commission will accept the Report on the 3-year experimental PBR filed September 28, 2001.

2. Western's pilot PBR, as modified, will be extended for a period of 4 years.

3. Western will issue a Request for Proposal for a new gas supply contract.

4. The sharing mechanism will include two bands: (1) 0 percent to 2 percent; and (2) over 2 percent. If Western contracts with a third party to manage its gas supply, the sharing ratio in the first band will be 70/30 in favor of the ratepayer and the sharing ratio for the second band will be 50/50. If Western manages its own gas supply, the sharing ratio for the first band will be 75/25 in favor of the ratepayers, and the sharing ratio for the second band will be 50/50.

5. The GAIF will be the simple average of the indices for National Gas Week, Gas Daily, Inside FERC's Gas Market Report and the NYMEX. If the supply is managed "in-house," the NYMEX will not be part of the benchmark.

6. Intra-month swing gas will be benchmarked against Gas Daily only.

7. The capacity threshold requirement will be eliminated from the TIF.

8. The OSSIF will be expanded to include off-system sales of storage services.

9. Western withdraws its request for the Storage Development and Cost Recovery Factor mechanism.

10. Western will extend its existing gas supply contract with Woodward until it either resumes management itself or contracts with a new supplier.

11. No later than 3 months from the first day of the month following the month the Order is entered, Western will report to the Commission that it has elected to manage its own gas supply needs or it will file an application for approval of a new third-party gas supply contract.

12. The effective date of the Commission's Order will be the first day of the month following the month in which the Commission enters its Order.

IT IS THEREFORE ORDERED that:

1. The Settlement set forth in Appendix A to this Order is hereby incorporated into this Order as if fully set forth herein.

2. The terms and conditions set forth in the Settlement are approved.

3. The tariff changes included in Exhibit 1 of the Settlement are fair, just and reasonable.

4. Any party wishing to exercise its right to withdraw from the Settlement shall notify the Commission in writing of its intent within 10 working days of the date of this Order.

5. If the Settlement is withdrawn due to any party's withdrawal from the Settlement, this Order is vacated without further Order of the Commission.

6. Within 20 days from the date of this Order, Western shall file with the Commission revised tariff sheets setting out the rates and tariffs approved herein. These tariff sheets shall show their date of issue, the effective date, and that they were issued by authority of this Order.

Done at Frankfort, Kentucky, this 25th day of March, 2002.

By the Commission

ATTEST:

Thomas M. Dorman

Executive Director

APPENDIX A

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2001-00317 DATED March 25, 2002

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

RECEIVED

FEB 18 2002

PUBLIC SERVICE COMMISSION

In the Matter of:

MODIFICATION TO WESTERN KENTUCKY GAS COMPANY, A DIVISION OF ATMOS ENERGY CORPORATION, GAS COST ADJUSTMENT TO INCORPORATE AN EXPERIMENTAL PERFORMANCE BASED RATEMAKING MECHANISM (PBR)) Case No. 2001-317

SETTLEMENT AGREEMENT

THIS SETTLEMENT AGREEMENT is made and entered into this 18th day of February, 2002 by and between the Attorney General of the Commonwealth of Kentucky, by and through his Office for Rate Intervention (the "Attorney General") and Western Kentucky Gas Company ("Western").

WITNESSETH: That whereas, on September 28, 2001, Western, pursuant to the Commission's Order of June 1, 1998 in Case No. 97-513, submitted its report on the results of the three (3) year experimental Performance Based Ratemaking ("PBR") and further applied to the Commission for an Order modifying and extending Western's PBR for an additional term of five (5) years commencing as of April 1, 2002; and,

WHEREAS, the Commission assigned Western's aforesaid application Case No. 2001-317; and,

WHEREAS, on October 16, 2001, the Attorney General filed for full intervention in this proceeding to represent the consumers' interests; and, WHEREAS, the Commission granted the Attorney General full intervention in this proceeding by Order dated October 19, 2001; and,

WHEREAS, pursuant to the Commission's procedural schedule extensive discovery has been exchanged by and among the parties and the Commission Staff; and,

WHEREAS, an informal conference among the Attorney General, Western and the Commission Staff was held pursuant to 807 KAR 5:001 Section 4 (4) in order to provide for the opportunity for settlement on January 29, 2002; and,

WHEREAS, as a result of that conference Western and the Attorney General have reached agreement on all issues relating to Western's pending application for modification and extension of its PBR; and,

WHEREAS, the Attorney General and Western have agreed to submit this settlement agreement to the Commission with the request that it be approved and adopted; and,

WHEREAS, the parties believe that the terms of the settlement set forth below are fair, just and reasonable and are in the best interest of Western and its ratepayers; and,

NOW THEREFORE, the parties hereby stipulate and agree to the following:

1. The Report filed by Western on September 28, 2001, concerning the results of its three (3) year experimental PBR should be accepted by the Commission.

2. Western's existing PBR, as modified in this settlement, should be extended for a term of four (4) years commencing as of the effective date contained in the Commission's final order in this proceeding. Western agrees to file its report concerning the results of the initial three (3) years of the PBR within sixty (60) days of the end of the third year.

3. Western's existing gas supply agreement will expire at the termination of Western's existing PBR. Upon entry of an order by the Commission approving this settlement agreement, Western agrees to promptly issue a request for proposal ("RFP") for a new gas supply contract to interested and qualified bidders. The RFP will include those terms set forth in Exhibit "A", page 3 of Western's Initial PBR Report, except as modified by this Settlement Agreement.

4. Under Western's current PBR, the sharing ratio under which variances between actual costs and benchmark costs are shared between ratepayers and shareholders is 50/50. The parties have agreed to modify the sharing ratio to provide for a sliding scale mechanism, having two bands. The first band will cover gas cost savings or excess gas costs from 0% up to and including 2.0%. The second band will cover variances of more than 2.0%. In the event Western enters into a third party gas supply agreement under paragraph 3 of this agreement, and for so long as gas is supplied

pursuant to that agreement, the sharing ratio for band one shall be 70/30 in favor of ratepayers. The sharing ratio for band two shall be 50/50. In the event Western does not award the gas supply contract or must otherwise commence "in-house" management and operation of its gas supply needs, then for so long as it engages in "in-house management" the sharing ratio for band one shall be 75/25 in favor of ratepayers and the sharing ratio for band two shall be 50/50.

5. As to the Gas Acquisition Index Factor ("GAIF"), for the purposes of issuing the RFP under paragraph three of this agreement, and in the event a third party gas supply agreement is issued under that paragraph, it is agreed that the simple average of the four current indices (National Gas Week; Gas Daily; Inside F.E.R.C.'s Gas Market Report; and, New York Mercantile Exchange (NYMEX)) for the Base Load will remain as currently specified in Western's tariffs. In the event Western does not award the gas supply contract of a third party or must otherwise commence "in-house" management and operation of its gas supply needs, the NYMEX closing prices will be removed from the GAIF as a benchmark index for Base Load and Western shall submit a revised tariff to that effect. However, as for intra-month swing purchases, Gas Daily will be the sole benchmark index.

6. As to the Transportation Index Factor ("TIF"), FERC approved pipeline transportation rates will continue to serve as the benchmarks against which Western's negotiated, discounted pipeline rates are measured. Additionally, the capacity release threshold ("CRT") required by the Commission in Western's initial PBR will be eliminated.

7. The existing Off-System Sales Index Factor ("OSSIF") will be modified to add off system sales of storage services. Western acknowledges that the Commission will closely monitor any such activity to insure that there is no detrimental impact on Western's system customers, either from a reliability perspective or from a cost perspective.

8. Western withdraws its request for a proposed Storage Development and Cost Recovery Factor ("SDRF") mechanism.

9. It is agreed that upon approval of this settlement agreement by the Commission, Western will file the attached amended tariff sheets which are marked as Exhibits "1", pages 29 A through 29 K.1, and which are incorporated herein by reference.

10. If the Commission accepts this settlement agreement, it will be necessary either to extend the contract between Woodward and Western or to have Western resume its gas supply operations itself between the date the Order is entered and a new contract is let under the RFP issued pursuant to paragraph 3 hereof, or a decision

is made that no new contract shall be let and Western will resume its own gas supply operations. Woodward has agreed to extend the contract with Western on a month to month basis during the interim period upon the same terms and conditions as the original contract. For purposes of this Settlement Agreement, "Interim Period" shall mean that period of time commencing as of the effective date of the Commission's order accepting this Settlement Agreement, and ending at such time as the Commission grants final approval to a new third party gas supply agreement entered into by Western pursuant to the provisions of paragraph 3 of this agreement <u>or</u> at such time as Western elects not to award a third party gas supply contract and commences "in-house" management and operation of its gas supply needs, whichever first occurs. Western shall report to the Commission that it has elected to commence "in-house" management of its gas supply needs <u>or</u> file an application for approval of a new third party gas supply agreement when the decision is made or the contract is placed, and in any event no later than three (3) months following the first day of the month following the month in which the order is entered. Under these circumstances the parties are agreed that the Woodward contract should be continued for the interim period. The benefits of the current PBR have been derived from the operation of the contract and the terms of that contract have been approved by the

Commission. An extension of the contract during the interim period is reasonable.

11. In the event the Commission accepts this Settlement Agreement, and in the further event Western's existing gas supply agreement is extended (the "Extended Agreement"), then and in those events, it is agreed that the amended tariff sheets attached hereto as Exhibit "1", pages 29 A through 29 K.1, will apply to all transactions under the Extended Agreement for the Interim Period.

In the event the Commission accepts this Settlement Agreement, the parties further request that the Commission's Order become effective on the first day of the month following the month in which the Commission enters such order.

12. This agreement is subject to the approval of the Commission. If the Commission fails to accept and approve this settlement agreement in its entirety, this proceeding will continue and neither the terms of this agreement nor any other matter raised during the settlement discussions will be admissible in any subsequent regulatory or judicial proceeding and will not be binding on either of the parties hereto.

13. If the Commission accepts and adopts this agreement in its entirety, neither the Attorney General nor Western will request any rehearing or bring any type of action for judicial review.

WITNESS the signatures of the parties hereto on this the day and date first hereinabove written.

ATTORNEY GENERAL OF THE COMMONWEALTH OF KENTUCKY

By: ______________________

WESTERN KENTUCKY GAS COMPANY

By: ______________________

Western Kentucky Gas Company
Modification of Performance-Based Ratemaking
Mechanism

Case No. 2001-317

Exhibit 1

Proposed Tariff Pages 29A – 20K.1

Issue Date: February 18, 2002

WESTERN KENTUCKY GAS COMPANY

PBR

Experimental Performance Based Rate Mechanism

Applicable

To all gas sold.

Rate Mechanism

The amount computed under each of the rate schedules to which this Performance Based Rate Mechanism is applicable shall be increased or decreased by the Performance Based Rate Recovery Factor (PBRRF) at a rate per 1,000 cubic-feet (Mcf) of monthly gas consumption. Demand costs and commodity costs shall be accumulated separately and included in the pipeline suppliers Demand Component and the Gas Supply Cost Component of the Gas Cost Adjustment (GCA), respectively. The PBRRF shall be determined for each 12-month period ended October 31 during the effective term of these experimental performance based ratemaking mechanisms, which 12-month period shall be defined as the PBR period.

The PBRRF shall be computed in accordance with the following formula:

$$PBRRF = (CSPBR + BA) / ES$$

Where:

ES = Expected Mcf sales, as reflected in the Company's GCA filing for the upcoming 12-month period beginning February 1.

CSPBR = Company Share of Performance Based Ratemaking Mechanism savings or expenses. The CSPBR shall be calculated as follows:

$$CSPBR = TPBRR \times ACSP$$

Where:

ACSP = Applicable Company Sharing Percentage

TPBRR = Total Performance Based Ratemaking Results. The TPBRR shall be savings or expenses created during the PBR period. TPBRR shall be calculated as follows:

$$TPBRR = (GAIF + TIF + OSSIF)$$

WESTERN KENTUCKY GAS COMPANY

PBR

Experimental Performance Based Rate Mechanism (Continued)

GAIF

GAIF = Gas Acquisition Index Factor. The GAIF shall be computed as follows:

$$GAIF = GAIFBL + GAIFSL$$

Where:

GAIFBL represents the Gas Acquisition Index Factor for Base Load system supply natural gas purchases.

GAIFSL represents the Gas Acquisition Index Factor for Swing Load system supply natural gas purchases.

GAIFBL

The GAIFBL shall be calculated by comparing the Total Annual Benchmark Gas Commodity Costs for Base Load (TABGCCBL) system supply natural gas purchases for the PBR period to the Total Annual Actual Gas Commodity Costs for Base Load (TAAGCCBL) system supply natural gas purchases during the same period to determine if any shared expenses or shared savings exist.

TABGCCBL represents the Total Annual Benchmark Gas Commodity Costs for Base Load gas purchases and equals the annual sum of the monthly Benchmark Gas Commodity Costs of gas purchased for Base Load (BGCCBL) system supply

BGCCBL represents Benchmark Gas Commodity Costs for Base Load gas purchases and shall be calculated on a monthly basis and accumulated for the PBR period. BGCCBL shall be calculated as follows:

$$BGCCBL = Sum\ [(APVBLi - PEFDCQBL) \times SAIBLi] + (PEFDCQBL \times DAIBL)$$

Where:

APVBL is the Actual Purchased Volumes of natural gas for Base Load system supply for the month. The APVBL shall include purchases necessary to cover retention volumes required by the pipeline as fuel.

ISSUED: February 18, 2002 EFFECTIVE:

(Issued by Authority of an Order of the Public Service Commission in Case No. 2001-317 dated).

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

WESTERN KENTUCKY GAS COMPANY

PBR

Experimental Performance Based Rate Mechanism (Continued)

"i" represents each supply area.

PEFDCQBL are the Base Load Purchases in Excess of Firm Daily Contract Quantities delivered to WKG's city gate. Firm Daily Contract Quantities are the maximum daily contract quantities which Company can deliver to its city gate under its various firm transportation agreements and arrangements.

SAIBL is the Supply Area Index factor for Base Load to be established for each supply area in which Company has firm transportation entitlements used to transport its natural gas purchases and for which price postings are available. The five supply areas are TGT-SL (Texas Gas Transmission-Zone SL), TGT-1 (Texas Gas Transmission-Zone 1), TGPL-0 (Tennessee Gas Pipeline-Zone 0), and TGPL-1 (Tennessee Gas Pipeline-Zone 1), and TGC-ELA (Trunkline Gas Company-ELA).

The monthly SAIBL for TGT-SL, TGT-1, TGPL-0, TGPL-1, and TGC-ELA shall be calculated using the following formula:

$$SAIBL = [I(1) + I(2) + I(3) + I(4)] / 4$$

Where:

"I" represents each index reflective of both supply area prices and price changes throughout the month in these various supply areas.

The indices for each supply zone are as follows:

SAIBL (TGT-SL)

I (1) is the average of weekly Natural Gas Week postings for Texas Gas Transmission Corporation Zone SL: South Louisiana as Spot Prices on Interstate Pipeline Systems
I (2) is the average of the daily high and low Gas Daily postings for Louisiana-Onshore South Texas Gas Zone SL averaged for the month.
I (3) is the Inside FERC – Gas Market Report first-of-the-month posting for Texas Gas Zone SL.
I (4) is the New York Mercantile Exchange Settled Closing Price.

ISSUED: February 18, 2002 EFFECTIVE:

(Issued by Authority of an Order of the Public Service Commission in Case 2001-317 dated)

ISSUED BY: William J Senter Vice President – Rates & Regulatory Affairs

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
First Revised SHEET No. 29D
Cancelling
Original SHEET No. 29D

WESTERN KENTUCKY GAS COMPANY

PBR

Experimental Performance Based Rate Mechanism (Continued) (T)

SAIBL (TGT-1)

I (1) is the average of weekly Natural Gas Week postings for Texas Gas Transmission Corporation Zone 1: North Louisiana as Spot Prices on Interstate Pipeline Systems.
I (2) is the average of the daily high and low Gas Daily postings for East Texas – North Louisiana Area - Texas Gas Zone 1 averaged for the month.
I (3) is the Inside FERC – Gas Market Report first-of-the-month posting for Texas Gas Zone 1.
I (4) is the New York Mercantile Exchange Settled Closing Price.

SAIBL (TGPL-0)

I (1) is the average of weekly Natural Gas Week postings for Tennessee Gas Pipeline Co. Zone 0: South Texas as Spot Prices on Interstate Pipeline Systems.
I (2) is the average of the daily high and low Gas Daily postings for Texas South – Corpus Christi – Tennessee and East Texas – North Louisiana Area – Tennessee, 100 leg averaged for the month.
I (3) is the Inside FERC – Gas Market Report first-of-the-month posting for Tennessee Zone 0.
I (4) is the New York Mercantile Exchange Settled Closing Price.

SAIBL (TGPL-1)

I (1) is the average of weekly Natural Gas Week postings for Tennessee Gas Pipeline Co. Zone 1: South Louisiana as Spot Prices on Interstate Pipeline Systems.
I (2) is the average of the daily high and low Gas Daily postings for Louisiana-Onshore South – 500 leg and 800 leg average for the month.
I (3) is the Inside FERC – Gas Market Report first-of-the-month posting for Tennessee Zone 1.
I (4) is the New York Mercantile Exchange Settled Closing Price.

SAIBL (TGC-ELA)

I (1) is the average of weekly Natural Gas Week postings for Trunkline Gas Co. East Louisiana as Spot Prices on Interstate Pipeline Systems.
I (2) is the average of the daily high and low Gas Daily postings for Louisiana-Onshore South, Trunkline ELA.
I (3) is the Inside FERC – Gas Market Report first-of-the-month posting for Trunkline Louisiana.
I (4) is the New York Mercantile Exchange Settled Closing Price

ISSUED: February 18, 2002 EFFECTIVE:

(Issued by Authority of an Order of the Public Service Commission in Case No. 2001-317 dated).

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

WESTERN KENTUCKY GAS COMPANY

PBR

Experimental Performance Based Rate Mechanism (Continued)

DAIBL is the Delivery Area Index factor for Base Load to be established for purchases made by Company when Company has fully utilized its pipeline quantity entitlements on a daily basis and which are for delivery to Company's city gate from Texas Gas Transmission's Zone 2, 3 or 4, Tennessee Gas Pipeline's Zone 2, or Trunkline Gas Company's Zone 1B.

The monthly DAIBL for TGT-2, 3, 4, TGPL-2, and TGC-1B shall be calculated using the following:

$$DAIBL = [I(1) + I(2) + I(3)] / 3$$

DAIBL (TGT-2, 3, & 4), (TGPL-2) and (TGC-1B)

I (1) is the average of weekly Natural Gas Week postings for Spot Prices on Interstate Pipeline Systems for Dominion – South.
I (2) is the average of the daily high and low Gas Daily postings the Daily Price Survey for Dominion – South Point.
I (3) is the Inside FERC – Gas Market Report first-of-the-month posting for Prices of Spot Gas Delivered to Pipeline for Dominion Transmission Inc. – Appalachia.

TAAGCCBL represents Company's Total Annual Actual Gas Commodity Costs for Base Load deliveries of natural gas purchased for system supply and is equal to the total monthly actual gas commodity costs.

To the extent that TAAGCCBL exceeds TABGCCBL for the PBR period, then the GAIFBL Shared Expenses shall be computed as follows:

$$\text{GAIFBL Shared Expenses} = TAAGCCBL - TABGCCBL$$

To the extent that TAAGCCBL is less than TABGCCBL for the PBR period, then the GAIFBL Shared Savings shall be computed as follows:

$$\text{GAIFBL Shared Savings} = TABGCCBL - TAAGCCBL$$

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
First Revised SHEET No. 29F
Cancelling
Original Sheet No. 29F

WESTERN KENTUCKY GAS COMPANY

PBR

Experimental Performance Based Rate Mechanism (Continued)

GAIFSL

The GAIFSL shall be calculated by comparing the Total Annual Benchmark Gas Commodity Costs for Swing Load (TABGCCSL) system supply natural gas purchases for swing load for the PBR period to the Total Annual Actual Gas Commodity Costs for Swing Load (TAAGCCSL) system supply natural gas purchases for during the same period to determine if any shared expenses or shared savings exist.

TABGCCSL represents the Total Annual Benchmark Gas Commodity Costs for Swing Load gas purchases and equals the monthly Benchmark Gas Commodity Costs of gas purchased for Swing Load system supply (BGCCSL).

BGCCSL represents Benchmark Gas Commodity Costs for Swing Load gas purchases and shall be calculated on a monthly basis and accumulated for the PBR period. BGCCSL shall be calculated as follows:

$$BGCCSL = \text{Sum } [(APVSLi - PEFDCQSL) \times SAISLi] + (PEFDCQSL \times DAISL)$$

Where:

APVSL is the Actual Purchased Volumes of natural gas for Swing Load system supply for the month. The APVSL shall include purchases necessary to cover retention volumes required by the pipeline as fuel.

"i" represents each supply area.

PEFDCQSL are the Purchases in Excess of Firm Daily Contract Quantities delivered to WKG's city gate. Firm Daily Contract Quantities are the maximum daily contract quantities which Company can deliver to its city gate under its various firm transportation agreements and arrangements.

SAISL is the Supply Area Index factor for Swing Load to be established for each supply area in which Company has firm transportation entitlements used to transport its natural gas purchases and for which price postings are available. The five supply areas are TGT-SL (Texas Gas Transmission-Zone SL), TGT-1 (Texas Gas Transmission-Zone 1), TGPL-0 (Tennessee Gas Pipeline-Zone 0), and TGPL-1 (Tennessee Gas Pipeline-Zone 1), and TGC-ELA (Trunkline Gas Company-ELA).

ISSUED: February 18, 2002 EFFECTIVE:

(Issued by Authority of an Order of the Public Service Commission in Case No. 2001-317 dated).

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

WESTERN KENTUCKY GAS COMPANY

PBR

Experimental Performance Based Rate Mechanism (Continued) (T)

The monthly SAISL for TGT-SL, TGT-1, TGPL-0, TGPL-1, and TGC-ELA shall be calculated using the following formula:

$$SAISLi = I(i)$$

Where:

"I" represents each index reflective of both supply area prices and price changes throughout the month in these various supply areas.

"i" represents each supply area.

The index for each supply zone is as follows:

SAISL (TGT-SL)

I (1) is the average of the daily high and low Gas Daily postings for Louisiana-Onshore South Texas Gas Zone SL averaged for the month.

SAISL (TGT-1)

I (2) is the average of the daily high and low Gas Daily postings for East Texas – North Louisiana Area - Texas Gas Zone 1 averaged for the month.

SAISL (TGPL-0)

I (3) is the average of the daily high and low Gas Daily postings for Texas South – Corpus Christi – Tennessee and East Texas – North Louisiana Area – Tennessee, 100 leg averaged for the month.

SAISL (TGPL-1)

I (4) is the average of the daily high and low Gas Daily postings for Louisiana-Onshore South – 500 leg and – 800 leg average for the month.

ISSUED: February 18, 2002 EFFECTIVE:

(Issued by Authority of an Order of the Public Service Commission in Case No. 2001-317 dated)

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

WESTERN KENTUCKY GAS COMPANY

PBR

Experimental Performance Based Rate Mechanism (Continued)

SAISL (TGC-ELA)

I (5) is the average of the daily high and low Gas Daily postings for Louisiana-Onshore South, Trunkline ELA.

DAISL is the Delivery Area Index factor for Swing Load to be established for purchases made by Company when Company has fully utilized its pipeline quantity entitlements on a daily basis and which are for delivery to Company's city gate from Texas Gas Transmission's Zone 2, 3 or 4, Tennessee Gas Pipeline's Zone 2, or Trunkline Gas Company's Zone 1B.

The monthly DAISL for TGT-2, 3, 4, TGPL-2, and TGC-1B shall be calculated using the following:

DAISL = I(1)

DAISL (TGT-2, 3, & 4), (TGPL-2) and (TGC-1B)

I (1) is the average of the daily high and low Gas Daily postings the Daily Price Survey for Dominion – South Point.

TAAGCCSL represents Company's Total Annual Actual Gas Commodity Costs for Swing Load deliveries to Company's city gate and is equal to the total monthly actual gas commodity costs.

To the extent that TAAGCCSL exceeds TABGCCSL for the PBR period, then the GAIFSL Shared Expenses shall be computed as follows:

GAIFSL Shared Expenses = TAAGCCSL - TABGCCSL

To the extent that TAAGCCSL is less than TABGCCSL for the PBR period, then the GAIFSL Shared Savings shall be computed as follows:

GAIFSL Shared Savings = TABGCCSL - TAAGCCSL

WESTERN KENTUCKY GAS COMPANY

PBR

Experimental Performance Based Rate Mechanism (Continued)

TIF

TIF = Transportation Index Factor. The Transportation Index Factor shall be calculated by comparing the Total Annual Benchmark Transportation Costs (TABTC) of natural gas transportation services during the PBR period to the Total Annual Actual Transportation Costs (TAATC) applicable to the same period to determine if any shared expenses or shared savings exist.

The Total Annual Benchmark Transportation Costs (TABTC) are calculated as follows:

TABTC = Annual Sum of Monthly BTC

Where:

BTC is the Benchmark Transportation Costs which include both pipeline demand and volumetric costs associated with natural gas pipeline transportation services. The BTC shall be accumulated for the PBR period and shall be calculated as follows:

BTC = Sum [BM (TGT) + BM (TGPL) + BM (TGC) + BM (PPL)]

Where:

BM (TGT) is the benchmark associated with Texas Gas Transmission Corporation.

BM (TGPL) is the benchmark associated with Tennessee Gas Pipeline Company.

BM (TGC) is the benchmark associated with Trunkline Gas Company.

BM (PPL) is the benchmark associated with a proxy pipeline. This benchmark, which will be determined at the time of purchase, will be used to benchmark purchases of transportation capacity from non-traditional sources.

The benchmark associated with each pipeline shall be calculated a follows:

BM (TGT) = (TPDR x DQ) + (TPCR x AV) + S&DB
BM (TGPL) = (TPDR x DQ) + (TPCR x AV) + S&DB
BM (TGC) = (TPDR x DQ) + (TPCR x AV) + S&DB
BM (PPL) = (TPDR x DQ) + (TPCR x AV) + S&DB

Where:

TPDR is the applicable Tariffed Pipeline Demand Rate.

ISSUED: February 18, 2002 EFFECTIVE:

(Issued by Authority of an Order of the Public Service Commission in Case No. 2001-317 dated).

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

WESTERN KENTUCKY GAS COMPANY

PBR

Experimental Performance Based Rate Mechanism (Continued) (T)

DQ is the Demand Quantities contracted for by the Company from the applicable transportation provider.

TPCR is the applicable Tariffed Pipeline Commodity Rate.

AV is the Actual Volumes delivered at Company's city gate by the applicable transportation provider for the month.

S&DB represents Surcharges, Direct Bills and other applicable amounts approved by the Federal Energy Regulatory Commission (FERC). Such amounts are limited to FERC approved charges such as surcharges, direct bills, cashouts, take-or-pay amounts, Gas Supply Realignment and other Order 636 transition costs.

The Total Annual Actual Transportation Costs (TAATC) paid by Company for the PBR period shall include both pipeline demand and volumetric costs associated with natural gas pipeline transportation services as well as all applicable FERC approved surcharges, direct bills included in S&DB, less actual capacity release credits. Such costs shall exclude labor related or other expenses typically classified as operating and maintenance expenses.

To the extent that TAATC exceeds TABTC for the PBR period, then the TIF Shared Expenses shall be computed as follows:

$$\text{TIF Shared Expenses} = \text{TAATC} - \text{TABTC}$$

To the extent that the TAATC is less than TABTC for the PBR period, then the TIF Shared Savings shall be computed as follows:

$$\text{TIF Shared Savings} = \text{TABTC} - \text{TAATC}$$

Should one of the Company's pipeline transporters file a rate change effective during any PBR period and bill such proposed rates subject to refund, the period over which the benchmark comparison is made for the relevant transportation costs will be extended for one or more 12 month periods, until the FERC has approved final settled rates, which will be used as the appropriate benchmark. Company will not share in any of the savings or expenses related to the affected pipeline until final settled rates are approved.

OSSIF

OSSIF - Off-System Sales Index Factor. The Off-System Sales Index Factor shall be equal to the Net Revenue from Off System Sales (NR).

WESTERN KENTUCKY GAS COMPANY

PBR

Experimental Performance Based Rate Mechanism (Continued)

Net Revenue is calculated as follows:

$$NR = OSREV - OOPC$$

Where:

OSREV is the total revenue associated with off-system sales and storage service transactions.

OOPC is the out-of-pocket costs associated with off-system sales and storage service transactions and shall be determined as follows.

$$OOPC = OOPC(GC) + OOPC(TC) + OOPC(SC) + OOPC(UGSC) + \text{Other Costs}$$

Where:

OOPC (GC) is the Out-of-Pocket Gas Costs associated with off-system sales transactions. For off-system sales utilizing Company's firm supply contracts, the OOPC (GC) shall be the incremental costs to purchase the gas available under Company's firm supply contracts. For off-system sales not using Company's firm supply contracts, the OOPC (GC) shall be the incremental costs to purchase the gas from other entities.

OOPC (TC) is the Out-of-Pocket Transportation Costs associated with off-system sales transactions. For off-system sales utilizing Company's firm transportation agreements, the OOPC (TC) shall be the incremental cost to use the transportation available under Company's firm supply contracts. For off-system sales not using Company's firm transportation agreements, the OOPC (TC) shall be the incremental costs to purchase the transportation form other entities.

OOPC (SC) is the Out-of-Pocket Storage Costs associated with off-system sales of storage. If this is gas in Company's own storage or gas stored with Tennessee Gas Pipeline it shall be priced at the average price of the gas in Company's storage during the month of sale. If this is gas from the storage component of Texas Gas's No-Notice Service, this gas shall be priced at the replacement costs

OOPC (UGSC) is the Out-of-Pocket Underground Storage Costs associated with off-system sales of storage services. For the off-systems sales of storage services utilizing Company's on-system storage, the OOPC(UGSC) shall include incremental storage losses, odorization, and other fuel-related costs such as purification, dehydration, and compression. Such costs shall exclude labor-related expenses

Other Costs represent all other incremental costs and include, but are not limited to, costs such as applicable sales taxes and excise fees. Such costs shall exclude labor-related or other expenses typically classified as operating and maintenance expenses.

ISSUED: February 18, 2002 EFFECTIVE:

(Issued by Authority of an Order of the Public Service Commission in Case No. 2001-317 dated)

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

WESTERN KENTUCKY GAS COMPANY

PBR
Experimental Performance Based Rate Mechanism (Continued)

ACSP

ACSP = Applicable Company Sharing Percentage. The ACSP shall be determined based on the PTAGSC.

Where:

PTAGSC = Percentage of Total Actual Gas Supply Costs. The PTAGSC shall be the TPBRR stated as a Percentage of Total Actual Gas Supply Costs and shall be calculated as follows:

PTAGSC = TPBRR / TAGSC

Where:

TAGSC = Total Actual Gas Supply Costs. The TAGSC shall be calculated as follows:

TAGSC = TAAGCCBL + TAAGCCSL + TAATC

If the absolute value of the PTAGSC is less than or equal to 2.0%, then the ACSP of 30% shall be applied to TPBRR to determine CSPBR. If the absolute value of the PTAGSC is greater than 2.0%, then the ACSP of 30% shall be applied to the amount of TPBRR that is equal to 2.0% of TAGSC to determine a portion of CSPBR, and the ACSP of 50% shall be applied to the amount of TPBRR that is in excess of 2.0% of TAGSC to determine a portion of CSPBR. These two portions are added together to produce the total CSPBR.

BA

BA = Balance Adjustment. The BA is used to reconcile the difference between the amount of revenues billed or credited through the CSPBR and previous application of the BA and revenues which should have been billed or credited, as follows:

1. For the CSPBR, the balance adjustment amount will be the difference between the amount billed in a 12 month period from the application of the CSPBR and the actual amount used to establish the CSPBR for the period.
2. For the BA, the balance adjustment amount will be the difference between the amount billed in a 12-month period from the application of the BA and the actual amount used to establish the BA for the period.

Review

Within 60 days of the end of the third year of the four-extension, the Company will file an assessment and review of the PBR mechanism for the first three years of the extension period. In that report and assessment, the Company will make any recommended modifications to the PBR mechanism

ISSUED: February 18, 2002 EFFECTIVE:

(Issued by Authority of an Order of the Public Service Commission in Case No. 2001-317 dated)

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

MODIFICATION TO LOUISVILLE GAS AND ELECTRIC COMPANY'S GAS SUPPLY CLAUSE TO INCORPORATE AN EXPERIMENTAL PERFORMANCE BASED RATEMAKING MECHANISM	)))))	CASE NO. 2001-017

ORDER

In Case No. 97-171, we approved an experimental gas procurement performance-based rate-making mechanism ("PBR") for Louisville Gas and Electric Company ("LG&E").[1] The experimental PBR, approved as a 3-year pilot, benchmarked all components of LG&E's gas cost and provided for a 50/50 sharing between ratepayers and shareholders of the amounts by which LG&E's gas costs varied from the benchmarks. The gas cost/gas procurement components contained in the PBR are: (1) Gas Acquisition Index Factor ("GAIF"); (2) Transportation Index Factor ("TIF"); and (3) Off-System Sales Index Factor ("OSSIF").

The GAIF includes LG&E's commodity costs, which are benchmarked based on the average of four indices, Gas Daily, Natural Gas Week, Inside FERC, and NYMEX closing prices. The GAIF also includes pipeline reservation fees that are benchmarked against the average of the actual reservation fees incurred by LG&E for the two most recent years.

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[1] Case No. 97-171, Modification to Louisville Gas and Electric Company's Gas Supply Clause to Incorporate an Experimental Performance-Based Ratemaking Mechanism, Order dated September 25, 1997

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The TIF includes pipeline transportation costs, which are benchmarked against LG&E's pipeline suppliers' FERC-approved transportation rates. LG&E's pipeline suppliers are Texas Gas Company and Tennessee Gas Pipeline Company. The release of pipeline capacity ("capacity release"), which is a sub-part of the TIF component of the PBR, is an activity in which LG&E had engaged prior to the implementation of the PBR. Therefore, the experimental PBR contained a capacity release threshold ("CRT") that LG&E had to exceed before shareholders could participate in any savings realized through capacity release activities. During the pilot, LG&E did not exceed the CRT.

The OSSIF reflects LG&E's net revenues, or savings, from off-system sales transactions. If revenues realized exceed the costs of such transactions, there are savings to be shared between ratepayers and shareholders. If costs exceed revenues, there are increased costs to be shared.

As per the Order approving the pilot PBR, LG&E filed a report and testimony on the 3-year pilot on December 28, 2000.[2] For the pilot period, LG&E reported total savings realized under the PBR of $19.6 million. Because shareholders were not able to participate in any savings achieved as a result of capacity release activity, ratepayers retained $10.7 million of the total while shareholders received $8.9 million through LG&E's Gas Supply Clause ("GSC").

A procedural schedule was established that provided for two rounds of discovery, intervenor testimony, rebuttal testimony, and a formal hearing. The Attorney General of the Commonwealth of Kentucky ("AG") is the only intervenor in this proceeding. A formal hearing in the matter was held September 5, 2001. LG&E filed a response to a

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[2] By Order dated November 5, 2000, LG&E was authorized to continue the PBR during the period the Commission was reviewing the operation of the 3-year PBR pilot.

supplemental data request from Commission Staff after the hearing. Briefs were not filed; therefore, the case stands submitted for decision.

SUMMARY OF PROPOSAL

LG&E proposes to retain the existing features of the PBR and to extend it for a period of 5 years. It also proposes to add two new features to the PBR. In the OSSIF category, LG&E presently can sell gas from storage, but cannot sell storage-related services. It proposes to add the sale of storage-related services as part of the OSSIF.[3] LG&E also proposes to add a fourth category to its PBR, a Storage Development and Cost Recovery Factor ("SDCF"), under which it would be able to recover costs and earn a return on new storage enhancement projects through its GSC on a real-time basis. Prior to beginning any such project it would be required to demonstrate that the overall costs were less expensive than the alternative, purchasing additional pipeline storage.[4]

ISSUES

Review of Pilot

LG&E contends that the PBR has functioned properly by providing incentives for it to manage its gas procurement activities in a manner that benefits both ratepayers and shareholders financially while not diminishing the reliability of its gas supply. The AG argues that the PBR should be terminated, based on his contention that LG&E has not demonstrated that ratepayers were better off under the PBR than they would have been under traditional rate-making absent the PBR. The AG contends that LG&E has

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[3] It would sell such services only if the prices were sufficient to cover its variable costs of providing the service and making a contribution to its fixed costs.

[4] If the project ultimately exceeded the cost of pipeline storage, the recoverable cost would be limited to the cost of the storage alternative.

not shown that the sum of the actual costs charged to ratepayers, plus what they were charged for the savings that flowed back to shareholders, was less than what the costs charged to ratepayers would have been absent the PBR.

LG&E claims it would be virtually impossible to attempt to reconstruct the pilot period and determine what its specific purchasing strategies and decisions would have been had there been no PBR during that time. According to LG&E, absent this reconstruction, calculating what its actual gas cost would have been during that period under traditional regulation is virtually impossible. The AG argues that LG&E should have been engaged in least-cost purchasing practices regardless of whether there was a PBR and that the costs achieved during the pilot can be viewed as the level of costs that would have been incurred in the absence of the PBR.

We are not persuaded by the AG's argument that the costs incurred during the PBR pilot accurately reflect the costs that would have been incurred during that period had there been no PBR. Absent the PBR, LG&E would have had different incentives and would have engaged in different purchasing activities. The exact extent of those differences and the quantification of their impact on LG&E's gas costs is what neither LG&E nor the AG can determine. Hence, there is no definitive means by which to say whether or not ratepayers were better or worse off under the PBR compared to traditional regulation. Because of the incentives built into the PBR, it is reasonable to conclude that LG&E's actual gas costs were less than what they would have been under traditional regulation. However, under the PBR ratepayers paid actual costs, plus the shareholders' portion of the savings achieved, based on the difference between actual costs and benchmarked costs. This creates uncertainty as to whether ratepayers paid more, or less, than they would have paid under traditional regulation.

Even with this uncertainty, we find that the AG has not made a strong argument for terminating the PBR. While LG&E cannot conclusively demonstrate that ratepayers are better off under the PBR, the AG cannot conclusively demonstrate that they would be better off under traditional regulation. Therefore, we find that the PBR should be continued, with modifications, on a pilot basis, to address this uncertainty. Those modifications are discussed in the following sections of this Order.

Modifications to PBR - GAIF

As an alternative to terminating the PBR, the AG makes the following recommendations: (1) that the GAIF commodity cost benchmarks be modified; (2) that the transportation cost benchmark in the TIF be modified; (3) that the proposed SDCF be denied; and (4) that the extended term of the PBR be limited to 2 years.

In the GAIF, the AG argues that the commodity benchmarks are set higher than the costs LG&E would incur under traditional regulation because they are based on contracted capacity in the four zones in which LG&E purchases gas rather than the actual volumes purchased. The AG also argues that using the mathematical average of four indices to establish the benchmark is inappropriate and that specific indices should be used to track purchases made on a monthly basis, a weekly basis, and a daily basis. The AG recommends that the benchmarks be modified to reflect actual volumes purchased and that the various indices be applied to the specific types of purchases that the given index reports (Gas Daily for daily purchases; Natural Gas Week for weekly purchases; and Inside FERC for monthly purchases). The AG would eliminate

NYMEX closing prices from the benchmark on the basis that LG&E's purchases are not structured to be comparable to what those closing prices represent.

LG&E argues that the AG's proposal to use actual volumes purchased in specific zones and to tie the price to a specific index depending upon whether the purchase is monthly, weekly, or daily, would be inappropriate, would create incentives for it to not follow market price changes throughout an entire calendar month, and would improperly insulate it from price risk. LG&E contends the AG's proposal would create inappropriate incentives which could subject it to after-the-fact disallowances because it followed the incentives rather than changes in market prices. LG&E also argues that NYMEX prices should remain in the benchmark calculation, contending that having two indices that reflect first-of-the-month prices (NYMEX and Inside FERC) along with two indices that reflect changing prices throughout the month (Gas Daily and Natural Gas Week) provides a better balance to the results.

The Commission sees some degree of merit in the AG's proposal. Given the uncertainty expressed previously, such a modification, during the pilot, would have resulted in lower GAIF benchmarks, resulting in a reduction in the calculated savings. A reduced level of savings would, therefore, have flowed back to shareholders, resulting in a larger portion of the savings being retained by ratepayers. However, we conclude that such modification would overly limit LG&E's flexibility to acquire gas at the lowest reasonable costs, which could result in higher actual costs than are achievable under the current structure, to the detriment of both shareholders and ratepayers. Therefore we find that the existing structure of the GAIF commodity benchmarks should be maintained.

We agree, however, with the AG on excluding NYMEX closing prices from the benchmark calculation. Given the nature of LG&E's commodity purchases, the evidence does not support their inclusion in the calculation. As to LG&E's argument concerning the appropriate balance of indices to be reflected in the benchmark, we find a more appropriate balance to be one which reflects one index for monthly purchases, Inside FERC, one index for weekly purchases, Natural Gas Week, and one index for daily purchases, Gas Daily.

Modifications to PBR – TIF

In the TIF, the AG argues that it is inappropriate to use FERC-approved pipeline transportation rates as the benchmarks against which LG&E's negotiated discounted pipeline rates should be measured. The AG claims that discounted rates are typical in the industry at present, that LG&E could have obtained discounts under traditional regulation, and that it should not be rewarded for doing something that other local distribution companies ("LDCs") have done, and are doing, without a PBR. The AG recommends that LG&E's current discounted pipeline transportation rates become the benchmarks against which its pipeline transportation rates would be measured in the future.

LG&E maintains that the AG's proposal, combined with his recommendation that the PBR be extended for only 2 years, would unfairly penalize it for its past efforts to achieve long-term cost savings and limit its ability to seek similar long-term savings in the future. LG&E claims that the AG's proposal does not recognize the linkage between obtaining pipeline discounts and the ability to release capacity. Nor does it recognize the potential impact on reliability related to federal regulatory policy that governs the conditions under which an LDC may terminate a pipeline contract or have right of first of refusal to continue to have access to pipeline capacity on a going-forward basis.

We find that no change to the current transportation cost benchmark, i.e. – the FERC-approved pipeline rates - should be implemented. While it appears that LG&E would likely have negotiated discounts of some amount in the absence of the PBR, there is no way of knowing what the magnitude and term of those discounts would have been, compared to the discounts negotiated under the PBR. Although, during the pilot, shareholders may have benefited where they otherwise would not have under traditional regulation, we recognize that observing areas that need correction, and then making the necessary corrections, is a primary reason for initially approving programs on a pilot basis. Setting the existing discounts as the benchmark, as proposed by the AG, appears to be a less-than-objective, somewhat punitive means of addressing this issue. We find the FERC-approved transportation rates to be the most objective benchmark for this component of costs. The Commission believes adjusting the sharing mechanism is a more appropriate means of handling any inequity in the benefits and risks between shareholders and ratepayers. That issue is discussed later in this Order.

Modification to PBR - OSSIF

LG&E proposes to add the sale of off-system storage services to the OSSIF component of the PBR. Such services include, but are not limited to, balancing services, displacement services, parking and loan services, and peaking and other storage services. LG&E emphasized that it would not offer to off-system customers firm storage services that would jeopardize service to firm on-system or native load customers. LG&E also emphasized that it would not offer to provide storage services

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unless the revenues from such services covered all variable costs and made some contribution to its fixed costs.

The AG made no proposals to modify the OSSIF; nor did he oppose LG&E's proposed addition of storage services. The Commission believes the addition of storage services as part of the OSSIF is reasonable, at least on a pilot basis, and will approve such addition as proposed. However, we intend to closely monitor this activity to ensure that there is no detrimental impact on LG&E's on-system customers, either from a reliability perspective or from a cost perspective.

Modification to PBR - SDRF

LG&E states that, from a cost recovery standpoint, the SDRF will level the playing field between developing on-system storage and purchasing pipeline storage. Under traditional cost recovery treatment, on-system storage facilities are considered part of an LDC's investment in plant on which it is permitted to earn a return through base rates, while pipeline storage costs are recovered through the gas cost adjustment ("GCA"), or GSC, in the case of LG&E. LG&E cites as precedent for its proposal the Commission's treatment of the costs incurred by Delta Natural Gas Company, Inc. ("Delta") for the development of its Canada Mountain storage field.

The AG opposes the SDRF on the basis that such costs are not gas procurement costs, and should not be eligible for recovery in the absence of a general rate application. The AG argues that to permit what LG&E has proposed would constitute single-issue rate-making and allow LG&E to recognize increases in one component of cost without recognizing changes in revenues and other costs.

LG&E points to the fact that a similar mechanism was previously approved for Delta; however, significant differences in circumstances distinguish LG&E's proposal from the Delta situation.[5] Delta had no on-system storage and was totally reliant on expensive purchased storage whereas LG&E already possesses a significant amount of on-system storage capacity. Delta had identified a specific storage development project, the Canada Mountain storage field, as a means of reducing its reliance on expensive pipeline storage; LG&E has no specific projects even in the planning stage at this time. Delta had developed a specific cost estimate for the project; LG&E, having no specific projects planned, has developed no such estimates.

In addition to these distinctions, the AG makes a valid argument against recovering such costs through LG&E's GSC. Absent extraordinary circumstances, such as those Delta faced, we find that the costs of storage development projects should continue to be recovered through base rates. However, having reached this conclusion, we believe that LG&E should have some incentive to pursue such projects. Therefore, although the proposed SDCF is denied, we find that LG&E should be able to submit storage development projects for Commission review, as proposed in the SDCF, to determine if a given project is a cost-effective alternative to purchasing pipeline storage. Projects that pass this review could then be treated as regulatory assets, with LG&E allowed to accrue AFUDC during construction to cover the carrying costs on its investment until such time as it can seek recovery through base rates. In this manner LG&E would not receive current cost recovery, but it would not forego cost recovery due

[5] Case No. 95-098, The Application of Delta Natural Gas Company, Inc., for an Order Authorizing the Purchase and Financing of the Canada Mountain Storage Field, Order dated September 7, 1995.

to the passage of time between beginning a project and recovering the costs through base rates.[6]

Sharing Ratio

LG&E proposed no change in the existing sharing ratio, under which variances between actual costs and benchmarked costs are shared 50/50 between ratepayers and shareholders. The issue of modifying the ratio was raised through data requests and cross-examination. Generally, both LG&E and the AG indicated that a change in the 50/50 ratio could be appropriate in conjunction with changes in other aspects of the PBR mechanism, and that such a change should reflect changes in the levels of risk to which LG&E is exposed.[7]

The two aspects of the PBR under which LG&E has had the greatest exposure to risk are capacity release and supply reservation fees. LG&E did not better the CRT at any time during the pilot due largely to changes within the industry, which reduced the value of pipeline capacity. In addition, there has been an upward trend in supply reservation fees during the pilot period. The Commission believes that the sharing ratio and the components of the PBR should be, and in fact are, interrelated in such a way that the potential risks and rewards to both ratepayers and shareholders inherent in the various components of the PBR should be reflected in the sharing ratio.

Having considered these risk factors, we find that the CRT should be removed from the PBR given the changes in the industry since the approval of the PBR pilot

[6] This, of course, depends upon whether LG&E files for base rate recovery in a timely manner.

[7] Such changes should also reflect the potential risks to which ratepayers are exposed.

However, we conclude that supply reservation fees should remain a component of the GAIF rather than being removed from the PBR. Contrary to its experience of consistent inability to exceed the CRT, LG&E achieved savings of $1,304,000 in one year of the pilot and incurred costs of $1,219,000 and $126,000, respectively, in the other years, for a 3-year net cost of $41,000 associated with supply reservation fees. In addition, we agree with LG&E that one of the strengths of its PBR is that it benchmarks every component, every dollar, of gas costs. For these reasons, we find that supply reservation fees should remain a component of the PBR.

Having found that the CRT should be removed from the PBR, and that the AG raises legitimate concerns as to whether ratepayers benefited from the results achieved during the pilot under the PBR versus what results could have been achieved under traditional regulation, we find that the 50/50 sharing does not accurately reflect the relative risks to ratepayers and shareholders. A properly structured PBR, with an appropriate sharing ratio, will better ensure that ratepayers benefit under the PBR compared to traditional regulation. During the pilot, LG&E consistently bettered the benchmarks each and every year by 4 to 6 percent, with an average savings as a percentage of total gas costs equal to 4.7 percent. Given LG&E's inability to demonstrate that ratepayers were better off under the PBR than they would have been under traditional regulation, a 50/50 sharing, after the elimination of the CRT, is unacceptable.

In evaluating possible modifications to the sharing ratio, we have taken into account the concerns expressed by LG&E about various asymmetrical types of sharing methods. Having considered those concerns, the Commission finds that a sliding scale extension will function in the same way as the cumulative 4-year pilot that was ultimately approved in Case No. 97-171. Within 60 days of the end of the third year, which will be October 31, 2004, LG&E should file a report on the 3-year period ended on that date to initiate a review proceeding of the same type as this proceeding. Throughout the 4-year period, LG&E will continue to file the quarterly reports with the Commission as it has during the initial pilot approved in Case No. 97-171.

The Commission, having considered the evidence of record and being otherwise sufficiently advised, HEREBY ORDERS that:

1. LG&E's pilot gas cost PBR, as modified herein, is extended for 4 years from the date of this Order.

2. LG&E's proposed storage development cost recovery factor is denied.

3. Within 60 days of the end of the third year of the 4-year extension, LG&E shall file an evaluation report on the results of the PBR for the first 3 years of the extension period, and the Commission shall review same for purposes of determining whether the PBR should be continued, modified, or terminated.

4. LG&E shall file quarterly reports of its activity under the extended PBR in the same manner as it has done during the initial PBR pilot period.

5. LG&E shall file its revised tariff sheets setting out the revisions to its PBR tariff, approved herein, within 20 days from the date of this Order.

Done at Frankfort, Kentucky, this 26th day of October, 2001.

By the Commission

ATTEST:

Executive Director

GENERAL TERMS AND CONDITIONS (Continued)

2. QUALITY

2.1 The provisions set forth in this Section 2 shall apply to all gas received by Transporter under this Tariff.

(a) The natural gas shall have a total heating value of not less than nine hundred and sixty-seven British thermal units per cubic foot (measured on a dry basis). Shipper may subject, or permit the subjection of, the natural gas to compression, cooling, cleaning and other processes and helium, natural gasoline, butane, propane, and any other hydrocarbons except methane may be removed prior to delivery to Transporter. In the event that the total heating value of gas, per cubic foot, in any month when determined as provided in Section 3.2 hereof, falls below nine hundred and sixty-seven British thermal units per cubic foot, Transporter shall have the option to refuse to accept said gas so long as said total heating value remains below nine hundred and sixty-seven British thermal units per cubic foot.

(b) All gas shall be commercially free (at prevailing pressure and temperature in Transporter's pipeline) from objectionable odors, dust, hydrocarbon liquids, water or other solid or liquid matters that might interfere with its merchantability or cause injury to persons or properties or interference with proper operation of the lines, regulators, meters or other appliances through which it flows and which might become separated from the gas in Transporter's facilities, and Transporter may require furnishing, installation, maintenance and operation of such drips, separators, heaters and other mechanical devices as may be necessary to effect compliance with such requirements (the installation of such equipment shall be subject to prior approval of Transporter as to the design and construction of such facilities, which approval shall not be unreasonably withheld).

(c) All gas shall contain no more than twenty (20) grains of total sulphur, nor more than one fourth (1/4) of one grain of hydrogen sulphide per one hundred (100) cubic feet as determined by methods to be mutually agreed upon.

(d) All gas shall not exceed ten parts per million by volume of oxygen, and Shipper shall make every reasonable effort to keep the gas free of oxygen.

(e) All gas shall not contain more than four percent (4%) by volume of a combined total of carbon dioxide and nitrogen components; provided, however, that the total carbon dioxide content shall not exceed three percent (3%) by volume.

Issued by: R. J. Kruse, Senior Vice President
Issued on: July 1, 2004 Effective on: July 1, 2004

GENERAL TERMS AND CONDITIONS (Continued)

(f) All gas shall have a temperature of not more than one hundred degrees (100() Fahrenheit.

(g) All gas shall have been dehydrated by Shipper for removal of entrained water present therein in a vapor state, and in no event contain more than seven (7) pounds of entrained water per million cubic feet, at a pressure base of fourteen and seventy three hundredths (14.73) pounds per square inch and a temperature of sixty degrees (60() Fahrenheit as determined by dew-point apparatus approved by the Bureau of Mines or such other apparatus as may be mutually agreed upon.

2.2 The design and construction of any facilities to be installed by Shipper in order to comply with the quality specifications in Section 2.1 shall be approved by Transporter prior to such facilities being placed in service.

2.3 Tests to determine sulphur, hydrogen sulphide, oxygen, carbon dioxide and nitrogen content shall be made by approved standard methods in general use in the gas industry.

2.4 Failure to conform to specifications against objectionable matter: If the gas offered for transportation to Transporter shall fail at any time to conform to any of the specifications set forth in Section 2.1, then Transporter shall notify Shipper and thereupon may, at Transporter's option, refuse to accept such gas pending correction by Shipper. Upon Shipper's failure to promptly remedy any deficiency in quality as specified in Section 2.1, Transporter may receive such gas and may make changes necessary to bring such gas into conformity with such specifications, and Shipper shall reimburse Transporter for any reasonable expense incurred by Shipper in effecting such changes.

2.5 Notwithstanding the exercise by Transporter of the options in Section 2 above, Shipper shall use its best efforts to correct any quality deficiency in the gas tendered for transportation. Further, notwithstanding Transporter's election under Section 2 above, Shipper shall reimburse Transporter for all expenses incurred in repairing injuries to Transporter's facilities resulting from deliveries of gas that do not conform to the quality specifications set forth in Section 2.1.

2.6 Transporter shall have the right to collect from all Shippers delivering gas to Transporter at a common Receipt Point their pro rata share of the cost of any additional gas analysis and quality control equipment that Transporter, at its reasonable discretion, determines is required to be installed at such Receipt Point to monitor the quality of gas delivered. With respect to Shippers subject to Rate Schedules IT, FT-A, and/or FT-GS, the collection shall be by means of an Incidental Charge.

GENERAL TERMS AND CONDITIONS (Continued)

2.7 Separation, Dehydration and Processing: Transporter at its reasonable discretion may require that some or all of the gas to be transported be processed to remove liquid and liquefiable hydrocarbons prior to delivery to Transporter or may require evidence that satisfactory arrangements have been made for the removal of liquid and liquefiable hydrocarbons at a separation and dehydration and/or processing plant on Transporter's system. In the event Transporter agrees that separation and dehydration and/or processing will occur after delivery of transportation gas to Transporter, Transporter and Shipper shall determine a mutually agreeable charge for the transportation of liquid and liquefiable hydrocarbons.

3. MEASUREMENT

3.1 Unit of Measurement: The transportation unit of gas received and delivered by Transporter shall be a dekatherm, unless otherwise indicated in this tariff.

3.2 Determination of Volume and Total Heating Value: The volume and the total heating value of gas received and delivered by Transporter shall be determined as follows:

(a) The unit of volume, for the purpose of measurement, shall be one (1) cubic foot of gas at a temperature of sixty degrees (60() Fahrenheit, and at a pressure of thirty-three hundredths (.33) pounds per square inch above an assumed atmospheric pressure of fourteen and four tenths (14.4) pounds per square inch (fourteen and seventy-three hundredths (14.73) pounds per square inch absolute pressure).

(b) The total heating value of the gas per cubic foot shall be determined by chromatograph located on Transporter's transmission system, or located so as to measure the heating value of the gas delivered into Transporter's transmission system, or any other method mutually agreed upon.

(c) Dekatherms delivered shall be determined by multiplying the Mcf delivered by the ratio of the total heating value of the gas delivered to 1,000. For purposes of this determination the specific gravity and heating value shall be determined at approximately the same time.

(d) The temperature of the gas passing through the meters shall be determined by a temperature transducer, other electronic temperature recording device, a recording thermometer, or any other method mutually agreed upon, so installed that it may properly record the temperature of the gas flowing through the meters.

Estimate of difference between Mr. Creamer's Approach and Reported in Audit

Month	Monthly Purchased Quantity	Actual Monthly Commodity Cost	Actual Per Unit Cost	Benchmark Monthly Commodity Cost	Benchmark Per Unit Cost
Jun-00	$1,028,583	$4,392,766	$4 2790	$4,478,124	$4 3622
Nov-00	1,270,798	$5,769,330	$4.5399	$5,865,200	$4 6154
Mar-01	950,718	$4,635,606	$4 8759	$4,705,895	$4 9496

	Actual Demand Cost	Actual Per Unit	Benchmark Demand Cost	
Jun-00	$1,185,342	$1 1546	$1,237,833	$1 2058
Nov-00	$1,957,357	$1 5403	$2,199,570	$1.7309
Mar-01	$1,709,689	$1 7983	$1,952,819	$2 0541

Actual		June	Nov	Mar
Commodity		$4 2790	$4.5399	$4.8759
Transportation		$1 1546	$1 5403	$1.7983
Bundled Rate		$5 4336	$6 0802	$6 6742
Benchmark				
Commodity		$4 3622	$4 6154	$4 9496
Transportation		$1 2058	$1 7309	$2 0541
Total		$5 5680	$6 3463	$7 0037
Lower Band 97.7%		$5 4399	$6 2003	$6 8426
Upper Band 102%		$5 6794	$6 4732	$7 1438
Gain/(loss)		$0 0063	$0 1201	$0 1684
Savings per Mr Creamer below band		$6,467	$152,623	$160,101
	%50% shared	$3,234	$76,311	$80,050
As Filed	Co. Share	$1,266	$101,420	$105,366
difference		-$2,028	$25,109	$25,316

Estimated Annual difference $111,867

Note: Estimated annual difference calculated by multiplying June difference above by seven months ~~and the average of November and March differences by five months~~