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May 5, 2004

VIA HAND DELIVERY

Ms Deborah Taylor Tate, Chairman
TENNESSEE REGULATORY AUTHORITY
460 James Robertson Parkway
Nashville, Tennessee 37243

Re: ***Petition of Chattanooga Gas Company for Approval of Adjustment of its Rates and Charges and Revised Tariff, Docket No. 04-00034***

Dear Chairman Tate:

Enclosed please find the original and thirteen (13) copies of our response, on behalf of the Intervenor Gas Technology Institute, to Chattanooga Gas Company's Data Request.

Should you have any questions concerning this filing, please do not hesitate to contact me.

Thanking you in advance for your assistance with this matter, I am

Very truly yours,

R. Dale Grimes

RDG/tn
Enclosures

cc: D Billye Sanders, Esq.
Timothy C. Phillips, Esq.
Vance L Broemel , Esq.
Henry M. Walker, Esq.
David C. Higney, Esq.
J. Richard Collier, Esq.

2474031 1

BEFORE THE TENNESSEE REGULATORY AUTHORITY
NASHVILLE, TENNESSEE

IN RE:	)	
	)	
PETITION OF CHATTANOOGA	)	
GAS COMPANY FOR APPROVAL	)	**DOCKET NO. 04-00034**
OF ADJUSTMENT OF ITS RATES	)	
AND CHARGES AND REVISED TARIFF	)	

GAS TECHNOLGY INSTITUTE'S RESPONSES TO CHATTANOOGA GAS COMPANY'S DATA REQUEST

Gas Technology Institute ("GTI") hereby responds to Chattanooga Gas Company's ("CGC") Data Requests as follows:

GENERAL OBJECTIONS

1. GTI objects to each of the Data Requests that seeks information or documents that are not relevant to the matters at issue in this docket nor reasonably calculated to lead to the discovery of admissible evidence.

2. GTI objects to each of the Data Requests and to the "Definitions," specifically including, but not limited to, paragraph 1 including "former" personnel, and the "Instructions," specifically including, but not limited to, paragraphs 2 and 4, to the extent they seek to expand the scope and obligations of discovery beyond that provided in the Tennessee Rules of Civil Procedure and the Rules of this Authority.

3. GTI objects to each of the Data Requests that seeks information protected by the attorney-client privilege, the work product doctrine, and/or any other applicable privilege or statutory or contractual restriction on disclosure. GTI will not provide information or documents that are protected from disclosure under any of the foregoing privileges or doctrines.

4. The responses set forth below is based upon information now available to GTI, and GTI reserves the right at any time to revise, correct, add to or clarify the objections and responses set forth herein. Failure to object herein shall not constitute a waiver of any objection that GTI may interpose as to future supplemental responses.

5. GTI is providing its responses herein without waiver of or prejudice to its right at any later time to raise objections to:

a. the competence, relevance, materiality, privilege, or admissibility of the response, the subject matter thereof or documents produced pursuant thereto;

b. all objections as to vagueness, ambiguity, and undue burden; and

c. all rights to object to the use of any documents or responses, or the subject matter thereof, in any subsequent proceedings, including, but not limited to, the hearing of this or any other action.

6. GTI objects to any production of proprietary and confidential information as premature prior to entry of an appropriate protective order.

7. The objections and statements set forth above are incorporated in the responses set forth below, and qualify GTI's response, whether explicitly or implicitly, that GTI will provide the information or documents sought.

GENERAL RESPONSE

1. All responses provided by Ron Edelstein, Director, State Regulatory Programs, GTI, 1700 S. Mt. Prospect Road, Des Plaines, IL 60018.

DATA RESPONSE NO. 1

Q. **On page 27 of his pre-filed testimony, Mr. Edelstein explains: Chattanooga Gas, with Authority oversight, will provide the final authorization as to where their research-funding dollars are applied from a list of candidate projects. What will be the source of the list of candidate projects?**

A. With respect to projects sponsored by GTI, as set forth in Exhibit 2 to the Qualifications and Direct Testimony of Ronald B. Edelstein, the source of these projects is suggestions on needed R&D from gas LDC's like Chattanooga Gas. They were derived from three R&D programs managed by GTI, Operations Technology Development (OTD), End-Use Technology Development (UTD), and Environmental Technology Development (ETD). As the Company elects to join one or more of these programs, it will have the ability to select which projects it wishes to fund on behalf of its consumers, suggest new projects not on the list for all LDC's that are part of the program to consider (thus leveraging its own funding to meet needs of Tennessee consumers), or not to fund any of the projects within the program. If the Company takes the latter course, it could seek projects from a non-GTI source, or hold the dollars in reserve until suitable projects are selected.

GTI reserves the right to supplement this response as the case develops and the parties' positions on this matter become clarified.

Gas Technology Institute
Response to
Chattanooga Gas Company's
Data Request No. 2
TRA Docket No. 04-00034
May 5, 2004

DATA RESPONSE NO. 2

Q. **On page 29 of his pre-filed testimony, Mr. Edelstein explains: "Chattanooga Gas, with Authority oversight, will have the ability to (1) choose specific R&D projects that will benefit its customers and (2) place these R&D dollars with GTI or other research organizations for customer-interest R&D purposes." What other research organizations are candidates to receive such funding?**

A. The organizations across the country performing natural gas R&D include NYGAS/NYSEARCH, Pipeline Research Committee International, Battelle Laboratories, Southwest Research Institute, and many universities.

Additionally, some of the GTI Operations Technology Development (OTD) projects are to be performed by others. The OTD internal inspection device for distribution mains is a NYGAS/NYSEARCH project. (NYGAS/NYSEARCH is a New York-based R&D management organization used by New York and other gas LDC's to manage gas operations R&D projects.)

Collaborative R&D for "looking ahead" of horizontal directional drilling technology to visualize in-ground obstacles is being conducted by Vermeer (ground penetrating radar), Mueller (electromagnetic), and Folsom (acoustic). These firms are R&D contractors.

GTI also works with universities on more basic-research oriented projects to perform fundamental research through laboratory proof of concept.

Gas Technology Institute
Response to
Chattanooga Gas Company's
Data Request No. 3
TRA Docket No. 04-00034
May 5, 2004

DATA RESPONSE NO. 3

Q. **On page 28 of his pre-flied testimony, Mr. Edelstein states: "There are 15 states currently authorizing research funding for gas-consumer-interest R&D." Please provide copies of the applicable orders and/or rules issued by the regulatory agency in each state adopting such funding.**

A. Documents will be produced separately.

DATA RESPONSE NO. 4

Q. **For each of the 15 states provide a summary of the accounting, reporting, auditing requirements that have been adopted relative to the billing, collecting, accounting for, and disbursement of funds collected through the GTI surcharge.**

A. Except to the extent set forth in the documents produced in response to Data Request No. 3, GTI is not aware of what specific arrangements each gas LDC in each of the 15 states has made with its public utility commission.

What we do know is that in New York, all the gas LDC's report back to the New York Public Service Commission (NYPSC) twice per year on R&D progress. The New York LDC's also place the R&D surcharge dollars in a balancing account, so that the dollars are used only for R&D. The NYPSC reserves the right to lower future R&D surcharges if the dollars are not allocated to projects within a year after their collection (e.g., all 2003 dollars need to be placed by the end of 2004).

In other states, reviews are conducted of the R&D projects once per year. In most cases, projects are not "pre-approved," but are subject to prudency reviews.

In Pennsylvania, where approval is still not final, Commission staff (ref: Docket No. M-00011462, April 19, 2001) suggested general R&D criteria that the projects need to meet (i.e., satisfy the objectives of at least one criterion). These were:

- Enhance health and safety
- Increase gas system reliability or integrity
- Enhance environmental quality
- Lower gas industry operating and maintenance costs

- Increase gas supply from emerging resources
- Increase (end-use) efficiency.

Gas Technology Institute
Response to
Chattanooga Gas Company's
Data Request No. 5
TRA Docket No. 04-00034
May 5, 2004

DATA RESPONSE NO. 5

Q. **Please provide a summary of the accounting, reporting, and auditing requirements currently in effect under the FERC oversight relative the billing, collecting, accounting for, and disbursement of the funds collected through the GTI surcharge.**

A. Many of these requirements are set forth in Federal Power Commission Order No. 566 (issued June 3, 1977) (Research, Development and Demonstration; Accounting; Advance Approval of Rate Treatment), Docket No. RM76-17.

GTI practices with respect to the items listed in this question are presented below:

Accounting: A software-based accounting system is used by GTI to track obligations of FERC-approved dollars to specific projects and contracts and invoices written against each project and paid out to such. GTI follows prescribed DCAA and FERC accounting procedures. GTI's accounting system uses an hourly task and project based person hour tracking system where each hour of every professional's time is tracked.

Reporting. FERC receives an R&D plan from GTI in June of each year, for review by FERC and intervenors by October. The Plan specifies the project objectives and deliverables, and accomplishments of the previous year. A five-year budget of each project is also provided to the FERC. GTI also reports on the benefits of its R&D each year to the FERC, and develops a national gas consumer benefit-cost ratio. (This benefit-cost ratio typically runs 8-1 to 10-1.)

Auditing· FERC retains full audit and prudency review rights, which it does on a case-by-case basis. GTI is also audited by the federal DCAA on behalf of the U S. Department of

Energy, and subscribes to DCAA accounting and auditing requirements. GTI is audited each year by an independent auditor, who reports to the Board of Directors.

Billing and Collecting: Collections for FERC-approved funds are conducted by the interstate natural gas pipelines on undiscounted sales and transport of interstate natural gas. In most cases, the FERC-approved dollars are collected via a pass-through mechanism in the purchased gas adjustment. Gas LDC's (and hence gas customers) are billed through the normal billing process. Dollars are remitted to GTI once per month by the interstate pipelines.

Disbursement of Funds: GTI disburses funds per contract and subcontract arrangement to GTI performing laboratories and other performing organizations based on invoices for actual R&D performed.

Gas Technology Institute
Response to
Chattanooga Gas Company's
Data Request No. 6
TRA Docket No. 04-00034
May 5, 2004

DATA RESPONSE NO. 6

Q. **Please provide a summary of the accounting, reporting, and auditing requirements that GTI would recommend the TRA adopt relative to the billing, collecting, accounting for, and disbursement of the funds collected through the GTI surcharge.**

A. Although GTI is providing the following suggested answers, it is up to the Authority to decide on appropriate accounting, reporting, and auditing requirements. In addition, the Company may have its own suggestions that should be considered.

Reporting: GTI recommends twice per year reporting to the Authority on the selection and progress of the R&D projects selected by the Company for R&D funding. The Authority would have the right to suggest projects for the Company to select for funding. The actual selection of projects would be performed by the Company on behalf of its customers, subject to Authority oversight. Once every four years, GTI would work with the Company to develop a benefit-cost analysis for the specific projects funded by the Company.

Collecting: Collections from the customer can be made through rates, the purchased gas adjustment, or via a separate tariff sheet, whatever the Authority determines. GTI suggests the use of a balancing account or similar procedure to ensure that the funds are retained for R&D purposes. The Company could report on balancing account balances as requested by the Authority.

Billing: Companies will be invoiced based on the contractual agreements they have signed with GTI and others.

Disbursement: Once funds are received by GTI from the Company, they will be disbursed to GTI performing laboratories or other performing organizations. GTI would report disbursement of funds by program or project on a twice per year basis.

Auditing: GTI would be subject to audit by the Authority as it is by FERC for its FERC-approved program or by DCAA for federal funding.

GTI reserves the right to supplement this response as the case develops and the parties' positions on this matter become clarified.

Gas Technology Institute
Response to
Chattanooga Gas Company's
Data Request No. 7
TRA Docket No. 04-00034
May 5, 2004

DATA RESPONSE NO. 7

Q. **In Tennessee, a large number of natural gas customers are served by municipal systems and natural gas utility districts that are not regulated by the Tennessee Regulatory Authority. The Authority cannot therefore require the customers of these systems and districts to participate in the funding of research and development. What percent of the customers in each of the states listed on page 29 of Mr. Edelstein's testimony are served by utilities not subject to rate regulation by the state utility commission?**

A. GTI objects to this request to the extent it seeks information equally available to the parties from public sources. Notwithstanding this objection, GTI states that it does not know the answer to this specific question.

GTI has considerable support from municipal utilities and natural gas utility districts not regulated by public utility commissions. Over 40 municipal utilities (and the Municipal Gas Authority of Georgia, representing another 40 companies) support GTI's voluntary R&D program, bringing in approximately $1 to $2 million per year out of the $17 million raised by LDC's (from the 15 states that have PUC-approved collection mechanisms) and municipals for the voluntary (non-FERC) R&D program. GTI receives about $10 million of these dollars, and almost all of the municipal funding. So approximately 10-20% of GTI's voluntary funding comes from municipals and natural gas utility districts, well over the proportion of volumes that pass through municipals.

In Tennessee, for instance, Middle Tennessee Gas, Memphis Gas Light & Water, Jackson

Energy Authority, and Brownsville have supported the GTI voluntary (non-FERC) program since 1999. These companies combined have raised $200,000-$400,000 per year from 1999-2003, depending on weather, a considerable contribution.

Gas Technology Institute
Response to
Chattanooga Gas Company's
Data Request No. 8
TRA Docket No. 04-00034
May 5, 2004

DATA RESPONSE NO. 8

Q. **Please identify the non-regulated natural gas systems in Tennessee that have volunteered to collect the surcharge for the funding of GTI and the number of customers served by such systems. Please provide evidence of such voluntary commitment, if any, i.e., contract, etc.**

A. In Tennessee, Middle Tennessee Gas, Memphis Gas Light & Water, Jackson Energy Authority, and Brownsville have supported the GTI voluntary (non-FERC) program since 1999. These companies combined have raised $200,000-$400,000 per year from 1999-2003, depending on weather, a considerable contribution.

The number of customers, from Pipeline & Gas Journal (Year 2000 data), is:

Memphis Gas Light & Water:	308,405
Middle Tennessee:	50,492
Brownsville:	5,085
Jackson Energy Authority	27,108
Total:	**391,090**

This is almost 40% of Tennessee's residential gas customers, using A.G.A. 2002 Gas Facts data (1.09 million residential customers shown). So the municipals are making a substantial contribution to voluntary R&D funding in Tennessee.

Proof of commitment is attached in the form of Allocation Forms, email and other written documents.

Gas Technology Institute
Response to
Chattanooga Gas Company's
Data Request No. 9
TRA Docket No. 04-00034
May 5, 2004

DATA RESPONSE NO. 9

Q. **Please provide a copy of the organizational document creating the GTI, e.g., the Charter or Articles of Incorporation.**

A. Documents will be produced separately.

DATA RESPONSE NO. 10

Q. **Please provide a copy of the Bylaws of GTI or other comparable documents pertaining to governance.**

A. Documents will be produced separately.

STATE OF ILLINOIS

COUNTY OF COOK

AFFIDAVIT

I, RONALD B. EDELSTEIN, Director of State Regulatory Programs for Gas Technology Institute, do hereby certify that the foregoing responses to the Data Requests from the Chattanooga Gas Company were prepared by me or under my supervision and are true and accurate to the best of my knowledge and information.

DATED this 4th day of May, 2004.

(signature)

RONALD EDELSTEIN
(printed name)

Sworn to and subscribed before me this 4th day of May, 2004.

Harriet V. Heidelmeier
NOTARY PUBLIC

My Commission Expires:

6/30/07

"OFFICIAL SEAL"
HARRIET V. HEIDELMEIER
Notary Public, State of Illinois
My Commission Expires 6/30/07

2473428 1

Respectfully submitted,

R. Dale Grimes (#6223)
BASS, BERRY & SIMS PLC
AmSouth Center
315 Deaderick Street, Suite 2700
Nashville, Tennessee 37238
(615) 742-6244

Attorneys for Gas Technology Institute

CERTIFICATE OF SERVICE

I hereby certify that a true and exact copy of the foregoing has been served on the following person(s), via the method(s) indicated, on this the 5 day of May, 2004:

[✓] Hand [ ] Mail [ ] Facsimile [✓] Electronic	D. Billye Sanders, Esq. Waller Lansden Dortch & Davis PLLC 511 Union Street, Suite 2100 P.O. Box 198966 Nashville, Tennessee 37219-1760
[ ] Hand [✓] Mail [ ] Facsimile [✓] Electronic	David C. Higney, Esq. Grant, Konvalinka & Harrison PC Republic Centre, 633 Chestnut Street, Suite 900 Chattanooga, TN 37450-0001
[✓] Hand [ ] Mail [ ] Facsimile [✓] Electronic	Timothy C. Phillips, Esq. Vance L. Broemel, Esq. Consumer Advocate and Protection Office of the Tennessee Attorney General P.O. Box 20207 Nashville, TN 37202
[✓] Hand [ ] Mail [ ] Facsimile [✓] Electronic	Henry Walker, Esq. Boult, Cummings, Conners & Berry, PLC 414 Union Street Suite 1600 Nashville TN 37219

BEFORE THE TENNESSEE REGULATORY AUTHORITY
NASHVILLE, TENNESSEE

IN RE:	)	
	)	
PETITION OF CHATTANOOGA	)	
GAS COMPANY FOR APPROVAL	)	**DOCKET NO. 04-00034**
OF ADJUSTMENT OF ITS RATES	)	
AND CHARGES AND REVISED TARIFF	)	

ATTACHMENT TO
GAS TECHNOLOGY INSTITUTE'S RESPONSES TO
CHATTANOOGA GAS COMPANY'S
<u>DATA REQUEST NO. 3 – PART ONE</u>

UNANIMOUS ADOPTION
THE COMMITTEE ON GAS OF THE
NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS (NARUC)

Resolution Encouraging Continued Support for Research and Development

Whereas, over the past 20 years, Gas Research Institute's (GRI) research program has demonstrated value to all gas consumers and the industry and the Federal Energy Regulatory Commission (FERC) has consistently found that GRI's R&D program delivers timely benefits to the gas consumers; and

Whereas, GRI has traditionally been funded through FERC-approved surcharges collected by interstate natural gas pipelines on gas volumes flowing through their systems; and

Whereas, since the stability of the long-term funding for GRI was first jeopardized in 1992, NARUC has passed six resolutions that address the benefits of GRI's R&D and GRI's funding, the central elements of which were:

- strong continuing support for full funding of GRI and its cooperative research program,
- recognition that GRI's research program delivers timely benefits to the gas industry and its customers,
- support for a long-term stable funding base for GRI's RD&D program, and;

Whereas, The Committee on Gas of the National Association of Regulatory Utility Commissioners (NARUC) has been actively involved in seeking an equitable solution for funding the research and development program of the Gas Research Institute (GRI) since the issue was raised in 1992; and

Whereas, as the gas industry transitioned toward becoming a more competitive industry, funding for GRI from 1994 through 1997 was via an interim mechanism established in a FERC-approved Settlement and Agreement (S&A); and

Whereas, pursuant to an April 29, 1998, FERC-approved S&A, funding for GRI's R&D program through FERC-approved surcharges collected by interstate pipelines will rapidly decline from 1998 through 2003 and will terminate in the year 2004; and

Whereas, National Association of Regulatory Commissioners (NARUC) continues to support cooperative R&D with broadly dispersed benefits and recognizes that a well-managed research program with broadly dispersed benefits, such as GRI's, enables the gas industry to serve all customers with the highest degree of reliability, maximum economic efficiency and minimum impact on the environment and should continue; and

Whereas, there is an opportunity to continue to fund broadly dispersed R&D which benefits the public interest without raising costs to the customer, and

Whereas, consistent with the 1998 FERC S&A, funding of R&D should not be mandatory, now therefore be it

Resolved, that the Board of Directors of the National Association of Regulatory Utility Commissioners, convened at its 1999 Winter Meeting in Washington, D.C., continues to believe that cooperative R&D with broadly dispersed customer benefits is an efficient way of leveraging R&D funds to provide research that is in both the public interest and the gas consumer interest, and be it further

Resolved, that the NARUC encourages all its members to continue to support a viable research and development program that benefits the natural gas industry and its customers to provide greater reliability, safety and environmental improvement

---

Sponsored by the Committee on Gas

Adopted 2/24/99

NATURAL GAS SECTION
ACTIVITIES
August 1998

Alabama Alagasco 8/98 (GSA Supply Adj.)

ALABAMA GAS CORPORATION

Gas Supply Adjustment (GSA) Recoveries

As part of its normal auditing activities, the section reviewed the GSA account balance. The company currently projects an over-recovery of about $1,500,000 at the end of the year.

	Over (Under) Recovery
May 1998	$5,180,974
June 1998	$4,886,382

GSA Audit

The section conducted its normal desk audit of the GSA work papers. A few areas where the staff needed further information were found. Section personnel visited the company to clarify these issues.

Gas Research Institute Funding

The section met with the company regarding continued funding of the Gas Research Institute (GRI). FERC recently began phasing out mandatory funding for GRI, which has historically been collected through pipeline rates. Alagasco has opted to continue its funding at current levels, for two years, instead of reducing it as the phase-out kicks in. GRI payments are now collected through pipeline rates and paid by the pipelines to GRI. Thus, as a pipeline cost, Alagasco's share is recovered through its GSA. Alagasco proposes to continue to recover its funding through the GSA although a portion of its funding will be paid directly to GRI. The staff is in agreement, and both are of the opinion that Commission approval is not needed as this method essentially mirrors present practice. The section also participated in the revision of the tariff language, which the company is expected to file soon.

Y2K Expenses

The section met with the company regarding Y2K expenses. The December 1990 order establishing the O&M cap for Alagasco stated that, "For purposes of the . . . cost control measurement, expenses related to changes in accounting principles and methods shall be excluded as appropriate."

The American Institute of Certified Public Accountants has issued Emerging Issues Task Force (EITF) Issue No. 96-14, *Accounting for the Costs Associated with Modifying Computer Software for the Year 2000*, which states in relevant part ". . . the costs incurred to modify computer software to correct the year 2000 problems should be expensed as incurred." Normally, computer software and upgrades or modifications to software are capitalized. Thus, this change in accounting method would allow Alagasco to exclude those expenses from the O&M cap. This will have no effect on the operation of RSE or on the company's rates; it will only allow Alagasco to avoid penalties which would otherwise occur under the operation of the O&M cap. The section has insisted that the company use only incremental costs to determine excludable expenses

Docket 020340 - GU

Non-fuel O&M expense example

Peoples TECO

patterns and, as such, were projected based on known or anticipated costs. A list of these items is contained on MFR Schedule G-6, page 8.

Two O&M expense accounts are worthy of special mention here. Specifically, those are accounts 916 (Miscellaneous Sales Expense) and account 930 (Miscellaneous General Expenses) In account 916, the Company has included $250,000 for a new customer retention program that aims to increase gas appliance penetration to existing customers who have only one gas appliance. The program was developed to reduce the loss of this type of customer. Loss of these customers would ultimately harm remaining ratepayers as a result of both reduced gas revenues and an increase in rate base resulting from the cost of cutting and capping the lost customers' service lines In account 930, Peoples has included $500,000 for payments to industry organizations for research that were formerly included and recovered from ratepayers as part of the Company's Purchased Gas Adjustment. Pursuant to Commission Order No. PSC-01-2370-FOF-GU, the Company now records this expense in non-fuel O&M expense

Depreciation expense was calculated based on projected plant in service and using depreciation rates as proposed by the Company in Docket No 010383-GU in its application for approval of new depreciation rates The depreciation rates for which Peoples has sought approval are the result of a study performed by the Company as required by Commission Rule 25-7.045. Because there has been no final order in the referenced docket, the Company will make adjustments to the depreciation expense reflected on the MFR schedules as filed if the new depreciation

Testimony of J. Paul Higgins Filed 6/27/02

PEOPLES GAS SYSTEM
DOCKET NO. 000003-GU
SUBMITTED
FOR FILING
09/27/00

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

W. EDWARD ELLIOTT

Q. How are Gas Research institute charges treated in the Purchased Gas adjustment Cost Recovery Clause?

A. The Gas Research Institute ("GRI") is a industry-funded, independent research organization. GRI provides efficient and effective research and development of products, studies and processes that benefit all natural gas consumers The work performed by GRI helps lower the cost of gas and improve the efficiency of its use. Historically, GRI funding was mandated by the Federal Energy Regulatory Commission and recovered through surcharges applied to the FERC-regulated, interstate pipeline charges included in costs recovered through the PGA. In 1998 FERC ordered that GRI funding transition to fully voluntary funding by January 2004. Peoples Gas supports the goals of GRI since the products and services provided by GRI benefit our customers. Therefore, Peoples Gas has continued to support GRI at the previously mandated funding level and include the voluntary funds in the PGA. Peoples Gas expects to continue supporting GRI with voluntary funding at the previously mandatory level and to include the voluntary charges in the PGA, even when GRI funding is fully transitioned to voluntary.

WARNING:

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For an official paper copy, contact the Florida Public Service Commission at contact@psc state fl us or call (850) 413-6770. There may be a charge for the copy.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re. Purchased Gas Adjustment (PGA) True-Up.	DOCKET NO. 010003-GU ORDER NO. PSC-01-2370-FOF-GU ISSUED: December 7, 2001

The following Commissioners participated in the disposition of this matter:

E. LEON JACOBS, JR., Chairman

J TERRY DEASON

LILA A. JABER

BRAULIO L. BAEZ

MICHAEL A. PALECKI

APPEARANCES:

WAYNE L. SCHIEFELBEIN, ESQUIRE, Post Office Box 15856, Tallahassee, Florida 32317

On behalf of Chesapeake Utilities Corporation.

RICHARD D. MELSON, ESQUIRE, Hopping Green & Sams, P. A., P. O. Box 6526, Tallahassee, Florida 32314

On behalf of City Gas Company of Florida.

ANSLEY WATSON, JR., ESQUIRE, MacFarlane Ferguson & McMullen, Post Office Box 1531, Tampa, Florida 33601

On behalf of Peoples Gas System.

ROBERT D. VANDIVER, ESQUIRE, Office of Public Counsel, c/o The Florida Legislature, 111 West Madison Street, Room 812, Tallahassee, Florida 32399-1400 On behalf of the Citizens of the State of Florida.

WM. COCHRAN KEATING IV, Esquire, Florida Public Service Commission, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850

On behalf of the Commission Staff.

ORDER APPROVING PURCHASED GAS ADJUSTMENT TRUE-UP AMOUNTS

AND ESTABLISHING PURCHASED GAS COST RECOVERY FACTORS TO BE APPLIED DURING THE PERIOD JANUARY 2002 THROUGH DECEMBER 2002

As part of this Commission's continuing purchased gas adjustment true-up proceedings, an administrative hearing was held November 20, 2001, in this docket. Chesapeake Utilities Corporation, Florida Division; City Gas Company of Florida; Florida Public Utilities Company; Indiantown Gas Company; Peoples Gas System ("Peoples Gas"); Sebring Gas System, Inc.; St. Joe Natural Gas Company; and

South Florida Natural Gas Company submitted testimony and exhibits in support of their proposed final and estimated true-up amounts and their proposed purchased gas cost recovery factors. The Office of Public Counsel ("OPC") also participated as a party in this proceeding.

Prior to hearing, the parties reached agreement concerning all but one of the issues identified for resolution at hearing. These issues were presented to us as a stipulation. The remaining issue concerns recovery by Peoples Gas of amounts voluntarily paid to fund the Gas Research Institute ("GRI").

- STIPULATED ISSUES

The parties stipulated to the final and estimated true-up amounts and purchased gas cost recovery factors appropriate for each utility. We accept and approve the stipulations, set forth below, as reasonable and supported by competent, substantial evidence of record.

We find that the appropriate final purchased gas adjustment true-up amounts for the period January 2000 through December 2000 are as follows:

Chesapeake Utilities Corporation $1,363,675 Underrecovery

City Gas Company of Florida $1,241,776 Underrecovery

Florida Public Utilities $1,395,028 Underrecovery

Indiantown Gas Company $20,446 Overrecovery

Peoples Gas System $13,661,513 Underrecovery

Sebring Gas System, Inc. $6,642 Overrecovery

St. Joe Natural Gas Company $88,000 Underrecovery

South Florida Natural Gas Company $211,238 Underrecovery

We find that the estimated purchased gas adjustment true-up amounts for the period January 2001 through December 2001 are as follows:

Chesapeake Utilities Corporation $156,863 Underrecovery

City Gas Company of Florida $596,710 Underrecovery

Florida Public Utilities $1,761,048 Overrecovery

Indiantown Gas Company $25,598 Underrecovery

Peoples Gas System $17,262,427 Overrecovery

Sebring Gas System, Inc. $16,680 Overrecovery

St. Joe Natural Gas Company $46,800 Overrecovery

South Florida Natural Gas Company $211,229 Overrecovery

We find that the total purchased gas adjustment true-up amounts to be collected during the period January 2002 through December 2002 are as follows:

Chesapeake Utilities Corporation $1,520,538 Underrecovery

City Gas Company of Florida $1,838,486 Underrecovery

Florida Public Utilities $366,020 Overrecovery

Indiantown Gas Company $5,152 Underrecovery

Peoples Gas System $3,600,915 Overrecovery

Sebring Gas System, Inc. $23,322 Overrecovery

St. Joe Natural Gas Company $41,200 Underrecovery

South Florida Natural Gas Company $9 Underrecovery

We find that the appropriate levelized purchased gas cost recovery (cap) factors for the period January 2002 through December 2002 are as follows:

Chesapeake Utilities Corporation 109.142 cents per therm

City Gas Company of Florida 64.576 cents per therm

Florida Public Utilities 83.412 cents per therm

Indiantown Gas Company 86.159 cents per therm

Peoples Gas System 98.473 cents per therm

Sebring Gas System, Inc. 88.004 cents per therm

St. Joe Natural Gas Company 75.400 cents per therm

South Florida Natural Gas Company 98.183 cents per therm

We find that these factors shall be effective for all meter readings on or after January 1, 2002, beginning with the first or applicable billing cycle, for the period January 2002 through December 2002.

- PEOPLES GAS' VOLUNTARY GRI FUNDING

The only disputed issue queried whether voluntary funding of the GRI surcharge should be recovered through the purchased gas adjustment clause as proposed by Peoples Gas System. Peoples Gas and OPC stipulated to the facts set forth below and addressed this issue in oral argument.

In 1998, the Federal Energy Regulatory Commission ("FERC") approved a settlement concerning funding of GRI. Peoples Gas and OPC stipulated that GRI provides efficient and effective research and development of products, studies, and processes to the benefit of all natural gas consumers. Peoples Gas and OPC further stipulated that the work performed by GRI helps lower the cost of gas and improves the efficiency of its use Prior to the FERC-approved settlement, all GRI research and development projects were funded through FERC-approved surcharges collected by interstate natural gas pipelines Under the 1998 settlement, the former mandatory surcharges were to be phased out through 2004 to a voluntary system of charges by gas companies using the pipelines By resolution in 1999, the National Association of Regulatory Utility Commissioners encouraged all of its members to continue to support a viable research and development program that benefits the natural gas industry and its customers

Peoples Gas seeks recovery of voluntary payments made to GRI under this new regime Although a specific issue was not raised in the 2000 purchased gas adjustment docket, this Commission approved recovery of similar voluntary payments made in 1999 - the first year such payments were voluntary - through our approval of Peoples Gas' 1999 final true-up amount in that docket. The parties have stipulated that recovery of voluntary payments to GRI will not be sought in future purchased gas adjustment dockets, commencing in 2001. Thus, only recovery of the amount of Peoples Gas' voluntary payments to GRI in 2000, $166,400.18, is disputed in this proceeding.

Peoples Gas asserts that it made payments to GRI in 2000 because this Commission allowed recovery of similar voluntary GRI payments when we approved Peoples Gas' 1999 final true-up amount. Peoples Gas states that it is willing to forego recovery of voluntary GRI payments commencing in 2001 and will record any GRI voluntary funding expense in non-fuel O&M expenses for possible future recovery in a base rate proceeding. Peoples Gas argues, however, that because payments have already been made for 2000 in reliance on our prior decision, the payments for 2000 should be recoverable through the purchased gas adjustment clause.

OPC argues that these payments are voluntary and benefit Peoples Gas' stockholders as much as its ratepayers Therefore, OPC asserts, Peoples Gas' stockholders, not its ratepayers, should make these payments OPC also notes that Peoples Gas is the only company seeking recovery of these expenses in this docket.

Because our decision in the 2000 purchased gas adjustment docket signaled to Peoples Gas that we would allow recovery of these types of payments, we find that Peoples Gas shall be allowed recovery of its voluntary GRI payments for 2000 through the purchased gas adjustment clause. Commencing with the 2001 cost recovery period, any GRI voluntary funding expense shall be recovered in non-fuel O&M expenses for possible future recovery in a base rate proceeding.

Based on the foregoing, it is hereby

ORDERED by the Florida Public Service Commission that the findings set forth in the body of this Order are hereby approved. It is further

ORDERED that the utilities named herein are authorized to collect the purchased gas adjustment amounts and utilize the factors approved herein effective with all meter readings on or after January 1, 2001, beginning with the first or applicable billing cycle for the period January 2002 through December 2002. It is further

ORDERED that Peoples Gas System's voluntary GRI payments for 2000 shall be recovered through the purchased gas adjustment clause, and, commencing with the 2001 cost recovery period, any GRI voluntary funding expense shall be recovered in non-fuel O&M expenses for possible future recovery in a base rate proceeding.

By ORDER of the Florida Public Service Commission this 7th day of December, 2001.

BLANCA S BAYÓ, Director

Division of the Commission Clerk

and Administrative Services

By /s/ Kay Flynn

Kay Flynn, Chief

Bureau of Records and Hearing

Services

This is a facsimile copy. Go to the Commission's Web site, http://www.floridapsc.com or fax a request to 1-850-413-7118, for a copy of the order with signature.

(S E A L)

WCK/LHD

NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.569(1), Florida Statutes, to notify parties of any administrative hearing or judicial review of Commission orders that is available under Sections 120.57 or 120.68, Florida Statutes, as well as the procedures and time limits that apply. This notice should not be construed to mean all requests for an administrative hearing or judicial review will be granted or result in the relief sought

Any party adversely affected by the Commission's final action in this matter may request 1) reconsideration of the decision by filing a motion for reconsideration with the Director, Division of the Commission Clerk and Administrative Services, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, within fifteen (15) days of the issuance of this order in the form prescribed by Rule 25-22.060, Florida Administrative Code; or 2) judicial review by the Florida Supreme Court in the case of an electric, gas or telephone utility or the First District Court of Appeal in the case of a water and/or wastewater utility by filing a notice of appeal with the Director, Division of the Commission Clerk and Administrative Services and filing a copy of the notice of appeal and the filing fee with the appropriate court This filing must be completed within thirty (30) days after the issuance of this order, pursuant to Rule 9.110, Florida Rules of Appellate Procedure. The notice of appeal must be in the form specified in Rule 9.900(a), Florida Rules of Appellate Procedure.

2 copies me for file

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Purchased gas adjustment (PGA) true-up.	DOCKET NO. 990003-GU ORDER NO. PSC-99-2443-FOF-GU ISSUED: December 14, 1999

The following Commissioners participated in the disposition of this matter:

J. TERRY DEASON
SUSAN F. CLARK
E. LEON JACOBS, JR.

APPEARANCES:

MICHAEL A. PALECKI, Esquire, NUI Corporation, PMB 111-M, 3111-20 Mahan Drive, Tallahassee, Florida 32308
On behalf of City Gas Company of Florida.

STEPHEN C. BURGESS, Deputy Public Counsel, Office of Public Counsel, 111 West Madison Street, Room 812, Tallahassee, Florida 32399-1400
On behalf of the Citizens of the State of Florida.

WM. COCHRAN KEATING, Esquire, Florida Public Service Commission, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850
On behalf of the Commission Staff.

FINAL ORDER APPROVING PURCHASED GAS ADJUSTMENT TRUE-UP AMOUNTS AND ESTABLISHING PURCHASED GAS COST RECOVERY FACTORS TO BE APPLIED DURING THE PERIOD JANUARY 2000 THROUGH DECEMBER 2000

BY THE COMMISSION:

As part of this Commission's continuing purchased gas adjustment true-up proceedings, an administrative hearing was held November 22, 1999, in this docket. Chesapeake Utilities Corporation, Florida Division; City Gas Company of Florida; Florida Public Utilities Company; Indiantown Gas Company; Peoples Gas System, Inc.; Sebring Gas System, Inc.; St. Joe

Natural Gas Company; and South Florida Natural Gas Company submitted testimony and exhibits in support of their proposed final and estimated true-up amounts and their proposed purchased gas cost recovery factors. Prior to hearing, the parties reached agreement concerning all issues identified for resolution at hearing. Therefore, the case was presented to us as a stipulation.

The parties stipulated to the final and estimated true-up amounts and purchased gas cost recovery factors appropriate for each utility. We accept and approve the stipulations as reasonable and supported by competent, substantial evidence of record.

We find that the appropriate final purchased gas adjustment true-up amounts for the period April 1998 through December 1998 are as follows:

Chesapeake Utilities Corporation	$21,077	Underrecovery
City Gas Company of Florida	$1,121,676	Overrecovery
Florida Public Utilities Company	$185,992	Underrecovery
Indiantown Gas Company	$29,016	Underrecovery
Peoples Gas System, Inc.	$4,088,862	Overrecovery
Sebring Gas System, Inc.	$1,452	Underrecovery
St. Joe Natural Gas Company	$59,445	Overrecovery
South Florida Natural Gas Company	$26,970	Overrecovery

We find that the estimated purchased gas adjustment true-up amounts for the period January 1999 through December 1999 are as follows:

Chesapeake Utilities Corporation	$94,883	Overrecovery
City Gas Company of Florida	$1,073,447	Underrecovery
Florida Public Utilities Company	$253,448	Overrecovery

Indiantown Gas Company	$28,701 Overrecovery
Peoples Gas System, Inc.	$3,807,198 Underrecovery
Sebring Gas System, Inc.	$6,725 Underrecovery
St. Joe Natural Gas Company	$52,925 Overrecovery
South Florida Natural Gas Company	$115,104 Overrecovery

We find that the total purchased gas adjustment true-up amounts to be collected during the period January 2000 through December 2000 are as follows:

Chesapeake Utilities Corporation	$73,806 Overrecovery
City Gas Company of Florida	$48,229 Overrecovery
Florida Public Utilities Company	$67,456 Overrecovery
Indiantown Gas Company	$315 Underrecovery
Peoples Gas System, Inc.	$281,665 Overrecovery
Sebring Gas System, Inc.	$8,177 Underrecovery
St. Joe Natural Gas Company	$112,370 Overrecovery
South Florida Natural Gas Company	$142,074 Overrecovery

We find that the appropriate levelized purchased gas cost recovery (cap) factors for the period January 2000 through December 2000 are as follows:

Chesapeake Utilities Corporation	46.424 cents/therm
City Gas Company of Florida	49.002 cents/therm
Florida Public Utilities Company	50.050 cents/therm
Indiantown Gas Company	47.941 cents/therm
Peoples Gas System, Inc.	55.097 cents/therm
Sebring Gas System, Inc.	52.724 cents/therm

St. Joe Natural Gas Company	44.900 cents/therm
South Florida Natural Gas Company	31.066 cents/therm

We find that these factors shall be effective for all meter readings on or after January 1, 2000, beginning with the first or applicable billing cycle, for the period January 2000 through December 2000.

Based on the foregoing, it is hereby

ORDERED by the Florida Public Service Commission that the findings set forth in the body of this Order are hereby approved. It is further

ORDERED that the utilities named herein are authorized to collect the purchased gas cost recovery amounts and utilize the factors approved herein for bills rendered for meter readings taken between January 1, 2000, and December 31, 2000.

By ORDER of the Florida Public Service Commission this 14th day of December, 1999.

/s/ Blanca S. Bayó

BLANCA S. BAYÓ, Director
Division of Records and Reporting

This is a facsimile copy. A signed copy of the order may be obtained by calling 1-850-413-6770.

(S E A L)

WCK

NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

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Any party adversely affected by the Commission's final action in this matter may request: 1) reconsideration of the decision by filing a motion for reconsideration with the Director, Division of Records and Reporting, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, within fifteen (15) days of the issuance of this order in the form prescribed by Rule 25-22.060, Florida Administrative Code; or 2) judicial review by the Florida Supreme Court in the case of an electric, gas or telephone utility or the First District Court of Appeal in the case of a water and/or wastewater utility by filing a notice of appeal with the Director, Division of Records and reporting and filing a copy of the notice of appeal and the filing fee with the appropriate court. This filing must be completed within thirty (30) days after the issuance of this order, pursuant to Rule 9.110, Florida Rules of Appellate Procedure. The notice of appeal must be in the form specified in Rule 9.900(a), Florida Rules of Appellate Procedure.

Service Date
October 29, 1999

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF AVISTA CORPORATION DBA AVISTA UTILITIES — WASHINGTON WATER POWER DIVISION FOR AN ORDER APPROVING A CHANGE IN NATURAL GAS RATES AND CHARGES.	CASE NO. AVU-G-99-2 ORDER NO. 28189

On September 15, 1999, Avista Corporation dba Avista Utilities — Washington Water Power Division (Avista; Company) applied to the Idaho Public Utilities Commission (Commission) for authority to implement new rates and charges for natural gas service in the state of Idaho. Avista serves approximately 48,600 customers in Idaho. Over 48,000 of those customers are residential. As computed by the company, the total requested net annual revenue increase in Idaho is $2,708,000 (8.58%), which includes separate billing adjustments for contract customers as detailed below. The increase in price per therm to residential customers is approximately 8.41%. Residential customers using an average of 80 therms per month under the Company's proposal can expect an increase in their average monthly bill of $3.21. The change in rates and charges to other customers will vary according to customer class and usage. The Company has requested an effective date of November 1, 1999. The Company maintains that the public interest does not require a hearing on its Application and requests that the matter be processed under the Commission's Rules of Modified Procedure, i.e., by written submission rather than by hearing, IDAPA 31.01.01.201-204.

As part of this Purchase Gas Adjustment (PGA) filing, the Company is also requesting to collect $.0004 per therm from sales customers for remittance to the Gas Research Institute (GRI) for research and development (R&D) projects. GRI is requesting that local distribution companies (LDCs) contribute, on a voluntary basis, an annual amount equal to lost pipeline funding. It is estimated that the proposed customer charge of $.0004 per therm will provide approximately $31,000 on an annual basis.

The overall effect of the proposed changes, if authorized, would be to increase customer rates per therm in the follow amounts:

Service Date
October 29, 1999

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The overall effect of the proposed changes, if authorized, would be to increase customer rates per therm in the follow amounts:

Class Description & Schedule	$ Per Therm
General/Large General & Commercial (Schedules 101,111 &121)	$0.04012
Large General & Commercial Receiving Lump Sum Bill Credits or Charges (Schedules 112 & 122)	$0.02185
Interruptible Service & Interruptible Service Receiving Lump Sum Bill Credits or Charges (Schedules 131 & 132)	$0.01784
Transportation (Schedule 146)	$0

Schedule 155—Gas Rate Adjustment

Schedule 155—Gas Rate Adjustment (Idaho) is used by the Company to pass through any under- or over-collection of gas costs since its last tracker filing. The company estimates a net deferral amount of $1,245,411 owing from its customers as of June 30, 1999. The result is an increase in the Tariff Schedule 155 rates for Schedules 101, 111 and 121 customers of $0.01827/therm.

As per the Company's Application and to clear out residual balances in customer accounts the following large transportation and interruptible customers will receive individual billing charges and/or credits/refunds that include interest that has accumulated from the end of the test period to the date of Commission approval. Balances at the end of the test period were:

Kootenai Medical Center	($ 224)
Idaho Asphalt	($ 189)
Imsamet	$ 0
Hughes Greenhouse	($ 33)
Lignetics	$ 182
Louisiana Pacific (Sandpoint)	$2,345
Louisiana Pacific (Chilco)	($ 32)
Interstate Asphalt	$ 8,508
University of Idaho	$10,561
St. Joseph Hospital	$11,766
Coeur d'Alene Asphalt	($ 1,088)
Crown Pacific	$12,658

Potlatch will receive an individual (Sch 155) refund/credit of $3,462.

Schedule 150—Permanent Gas Cost Changes

Schedule 150—Permanent Gas Cost Changes (Idaho) is used by the Company to reflect continuing changes in the cost of purchasing and transporting gas for customers. Since rates were last approved, the net change in commodity, demand and storage gas costs results in an increase of $0.02185/therm for firm gas Schedules 101 through 122; an increase of $0.01784/therm for interruptible Schedules 131 and 132; and no change for transportation Schedule 146. As per the Company's Application, the resultant annual net increase in annual revenue requirement (Idaho) related to Schedule 150 changes is $1,462,698. The Company calculates its current weighted average cost of gas (WACOG) to be $0.19308, an increase of $0.02567 from the previous $0.16741.

On October 4, 1999, the Commission issued Notices of Application and Modified Procedure in Case No. AVU-G-99-2. The deadline for filing written comments or protests was October 22, 1999. Comments were filed by Commission Staff and a number of the Company's customers. Staff recommends that the Company's Application be approved. Staff reviewed the Company's filing and audited the information provided. In its comments, Staff notes that natural gas prices in the northwest appear to be trending up. A major factor cited for the increase is the addition of new pipeline capacity connecting the Canadian Provinces of British Columbia and Alberta to the mid-west and eastern U.S. markets. Whereas previously the Canadian gas was locked into the northwest and California markets, the Canadians, Staff states, are now able to sell their gas in more lucrative markets. Additional factors cited as contributing to the higher gas prices are an increase in oil prices and the tightening of gas supplies vis-à-vis demand.

The Commission has also received a number of letters, faxes and e-mails from Avista customers opposing the size of the proposed increase, questioning the necessity of an increase, expressing concern regarding the impact of the increase on fixed and low-income customers, questioning the nature of the review process and the Commission's role, and questioning whether the Company, which can recover its costs, has incentive to negotiate the lowest price for its customers.

COMMISSION FINDINGS

The Commission has reviewed and considered the Company's Application in Case No. AVU-G-99-2 together with the attached exhibits and workpapers. The Commission has also considered the comments and recommendations of Staff related to the Company's Application.

We further acknowledge the receipt of a number of letters, faxes and e-mails from Avista customers protesting the proposed increase. Despite the concerns raised by the Company's customers, we find that the public interest regarding the requested change in rates does not require a public hearing to consider the issues presented. Reference IDAPA 31.01.01.204.

The Commission appreciates the concerns raised by customers who oppose the rate increase. We note that the Company's Application is a limited gas tracker and not a general rate case. Items such as the CEO's salary package, the Company's affiliate enterprises and how the Company spends its profits are not at issue. As this Commission in prior Orders has previously observed, the nature of costs included in the Company's gas tracker Applications are generally external costs over which the Company has little or no control. Of exception in this case, the Company is asking to recover what is now a voluntary contribution to the Gas Resource Institute. We approve same because it has historically been recovered in the PGA as a pipeline cost and we believe the Company's customers will benefit from the Company's continued investment in research and development projects. Although we recognize the Company maintains an element of control in its contracting practices, the Commission has confidence that should the Company's actions appear out of ordinary or imprudent that the review process would reveal same. We continue to find the annual tracker mechanism to be a useful regulatory vehicle for tracking and adjusting for gas-related costs. In some years PGA trackers result in rate increases, in other years rate decreases. The most recent history is as follows:

1998	$1,117,000 or 4.04% increase	Order No. 27816
1997	$3,972,000 or 15.6 % increase	Order No. 27261
1996	$2,338,601 or 8.5 % decrease	Order No. 26662
1995	$4,850,000 or 15.68% decrease	Order No. 26283
1994	$1,026,000 or 3.98% decrease	Order No. 25708

There is equity in approving increases as well as decreases.

The Company in this case has requested a net annual revenue increase in Idaho of $2,708,000. (8.58%), which includes separate billing adjustments for contract customers as detailed above. Based on the Commission's review and consideration of the Application and record in Case No. AVU-G-99-2, we accept the Company's proposed rates, charges and adjustments as fair, just and reasonable. We further find to be reasonable an implementation date for new tariffs of November 1, 1999.

CONCLUSIONS OF LAW

The Idaho Public Utilities Commission has jurisdiction over this matter and Avista Corporation dba Avista Utilities—Washington Water Power Division, a gas utility, pursuant to the authority and power granted under Title 61, *Idaho Code* and the Commission's Rules of Procedure, IDAPA 31.01.01.000 *et seq.*

ORDER

In consideration of the foregoing and as more particularly described above, IT IS HEREBY ORDERED that Avista Corporation dba Avista Utilities—Washington Water Power Division be authorized to increase (change) its rates and charges in the manner requested in its Application and as reflected in the tariff schedules submitted in Case No. AVU-G-99-2 for effective date for implementation of November 1, 1999.

THIS IS A FINAL ORDER. Any person interested in this Order may petition for reconsideration within twenty-one (21) days of the service date of this Order. Within seven (7) days after any person has petitioned for reconsideration, any other person may cross-petition for reconsideration. See *Idaho Code* § 61-626.

DONE by Order of the Idaho Public Utilities Commission at Boise, Idaho this 28th day of October 1999.

DENNIS S. HANSEN, PRESIDENT

MARSHA H. SMITH, COMMISSIONER

PAUL KJELLANDER, COMMISSIONER

ATTEST:

Myrna J. Walters
Commission Secretary

vld/O:AVU-G-99-2_sw

Office of the Secretary
Service Date
July 30, 1999

IN TERMOUNTAIN

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF INTERMOUNTAIN GAS COMPANY FOR AUTHORITY TO CHANGE ITS PRICES.	))))	CASE NO. INT-G-99-1 ORDER NO. 28109

On May 14, 1999, Intermountain Gas Company (IGC; Company) filed an Application with the Idaho Public Utilities Commission (Commission) for authority to place into effect new rate schedules that would result in an overall increase of approximately $9.6 million in its annualized revenues. The increase reflects a change in the Company's cost of gas and the elimination and/or imposition of a number of temporary gas and transportation cost adjustments, surcharges and credits. The Company in its filing also proposes to balance out its Purchased Gas Cost Adjustment (PGA), Account 186. The PGA Account is a deferral mechanism for over- and under-collections and for realized savings on spot market gas purchases.

The proposed adjustments reflected in the Application include changes in costs billed IGC by Williams Gas Pipelines-West (WGP-W) and other transportation companies, the elimination of temporary surcharges and credits (INT-G-98-4), an increase in the Company's weighted average cost of gas (WACOG), the benefits generated from the Company's segmentation of its firm capacity rights on WGP-W's system, the inclusion of temporary surcharges and credits relating to gas and transportation related costs from the Company's deferred gas cost account (PGA Account 186), and an updated customer allocation of gas-related costs.

The Application proposes implementation of the following permanent and temporary changes, adjustments, surcharges and credits to IGC's tariff rates for natural gas service, sales and transportation:

Permanent Adjustments:

• INT-G-98-4 Elimination of Temporary Surcharges/Credits	($ 644,603)
• Change in WGP-W rates/charges	$1,963,300
• Change in storage costs	$ 457,385
• Cost of Gas Supply	$5,677,983

Temporary Surcharges or Credits

Deferred Gas Costs (IGC PGA Acct 186)

- NWP Refund Docket No. RP93-5 ($649,565)
- Variable Cost Collection Adjustment ($ 417,248)
- Uncollected Gas Costs $5,195,949
- Market Segmentation ($2,189,891)
- Storage credit ($ 465,603)
- Fixed Gas Cost Misc ($ 709,039)

As computed by the Company, the total requested increase in revenue on an annual basis is $9,637,020 or 8.46%. The net increase in sales gas revenues is $9,405,663 or 8.61%. The increase in T-1 transportation service revenues is $182,684 or 4.56%. The net increase in T-2 transportation service revenues is $48,673 or 6.52%. The annualized change in rates by class of service per Company calculation is as follows:

Gas Sales	Revenue	Avg Increase (Decrease) ¢/Therm	Avg Increase (Decrease) % Change	Proposed Avg Price $/Therm
RS-1 Residential	$1,212,193	3.416¢	5.66%	$0.63757
RS-2 Residential	$4,928,297	4.854¢	9.94%	$0.53698
GS-1 Genl Svc	$ 3,265,173	3.883¢	8.55%	$0.49323
LV-1 Large Vol. *				

* T-1 tariff price plus the Weighted Average Cost of Gas (WACOG), $0.18252

(Compare WACOG INT-G-98-4: $0.15684)

WACOG = total commodity cost of gas ÷ total purchase therms

Transportation	Revenue	Avg Increase (Decrease) ¢/Therm	Avg Increase (Decrease) % Change	Proposed Avg Price $/Therm
T-1 Transp.	$182,684	0.393¢	4.56%	$0.09003
T-2 Transp.	$ 48,673	0.224¢	6.52%	$0.03661

With the exception of the Industrial Class, IGC proposes to allocate the change in rates to each of its customer classes in accordance with its Purchased Gas Cost Adjustment tariff and approved cost-of-service methodology. (Ref. Case Nos. INT-G-95-1, INT-G-88-2, U-1034-137). Because there are no fixed costs currently recovered in the tailblock of IGC's T-1 tariff and because the proposed increase in the T-1 tariff is related to fixed costs (except for TF-1 commodity charge), a cents-per-therm increase is made only to the first two blocks of the T-1 tariff. All three blocks of IGC's proposed T-1 tariff have been adjusted to include WGP-W's firm transportation TF-1 commodity charge. The proposed increase in the T-2 tariff (except for TF-1 commodity charge) is fixed cost related and, therefore, a cents per therm increase was made only to the T-2 demand charge. The commodity charge component of the T-2 tariff was adjusted to include WGP-W's firm transportation TF-1 commodity charge.

Intermountain Gas requested that its Application be processed under Modified Procedure, i.e., by written submission rather that by hearing. Commission Notices of Application and Modified Procedure in Case No. INT-G-99-1 issued on June 4, 1999. The deadline for filing written comments was June 24, 1999. Reference Commission Rules of Procedure, IDAPA 31.01.01.201-204. Timely comments were filed by Commission Staff and six of the Company's customers. Three customer comments were filed out of time on June 25.

On July 1, 1999, the Commission in Case No. INT-G-99-1 issued Order No. 28087. The Company in its Application had requested an effective date of July 1, 1999. The Commission in its Order suspended the proposed July 1 effective date until August 1, 1999, making the following findings:

> We find, as the Company acknowledges, that Intermountain Gas has the affirmative burden of proof as to reasonableness regarding contract fees paid to its affiliate IGI Resources. Reference *Boise Water Corp v. Idaho*

> *PUC*, 97 Idaho 832, 555 P.2d 163 (1976). We note that the Company did not make such an offer of proof in its Application filing. It is only with the Company's filing of June 25th that we are provided with such offer of proof. The Commission finds that it needs more time to consider the Staff proposed "adjustments and Company responses."

Reference *Idaho Code* § 61-622.

The previously filed comments can be summarized as follows:

Customer Comments

The Company's customers object to the proposed increase, object to the inadequate notice provided by the Company and request a hearing. To grant the increase, one customer suggests, will eliminate the Company's incentive to reduce its external and internal expenses by eliminating inefficiencies. The size of the proposed increase is objected to by another customer who contends that it will create hardship among those of the elderly whose only income is social security. "What do we do," she queries, "when we can no longer pay the price to keep warm?"

An additional customer, Ms. Sharon Ullman, in comments filed June 24 requests that the Commission reconsider its Order No. 28068 and suspend the proposed July 1 effective date for at least 30 days and hold a public hearing or provide further opportunity for written comment and closer scrutiny of the Company's Application. Ms. Ullman notes that she did not receive the June 23 postmarked "customer notice" from IGC until June 24, the same day as the Commission deadline for filing written comments or protests. The Company notice, Ms. Ullman contends, is woefully inadequate. It is, she states, essentially a public relations document that says absolutely nothing to indicate that customer comments and/or protests are being accepted by the Commission.

Ms. Ullman in her letter also relates some frustration in her three attempts to obtain information from the Company's general manager of marketing and public relations, who, she states, instead of simply providing answers to questions regarding the Application, chose to question her with apparent suspicion about who she was and her interest in the case.

Ms. Ullman contends that by holding a public hearing in this case, or at the very least extending the public comment period, the Commission can help the public to understand that their circumstances, opinions and input are of concern to the Commission and that public input is welcomed and adequately sought.

Staff Comments

Commission Staff proposes a number of adjustments to the Company's filing, reducing the Company proposed $9,637,020 increase in revenue requirement by $1,258,409, for an adjusted total annual revenue increase of $8,378,611.

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IGI Resources, on the other hand, bears no risk for the cost of gas as all costs for IGC's supplies are directly passed to the customers through the PGA. This includes the long-term contracts that are at the index plus an adder to the producer in addition to the IGI management fee.

Consider an example with an Indexed WACOG of .150¢ per therm; for WWP the cost of a therm would then be .155¢ per therm (.150¢ +.005¢) if Avista Energy had to pay .175¢ per therm for the gas the cost to WWP is still .155¢ per therm. For IGC the producer index price could be .150¢ per therm plus .005¢ per therm or it could be .175¢ per therm plus .005¢ per therm. Then IGI Resources would add their .005¢ per therm for a total supply cost of .160¢ per therm or .185¢ per therm which would then be passed on to the ratepayer in the PGA (note this example is not based on actual costs to either company and does not show IGC hedges). The point of this example is not the cost, but that IGI Resources has no risk for the cost while Avista Energy does.

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COMMISSION FINDINGS

The Commission has now reviewed and fully considered the filings of record in Case No. INT-G-99-1 including the comments filed by Commission Staff, the Company's customers and the reply comments of Intermountain Gas. We continue to find that the public interest regarding the requested change in rates does not require a public hearing to consider the issues presented and that it is reasonable to process the Application and issue an Order without further notice or public comment. Reference IDAPA 31.01.01.204.

We address Staff recommendations and proposed adjustments in this case as follows:

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The Commission finds that it is reasonable for IGC to leverage its investment in research and development (R&D) by contributing to cooperative research organizations such as Gas Research Institute (GRI). We have long recognized the value and benefit to gas customers and the industry of GRI's R&D programs and continue to support the Company's involvement in GRI. We recognize that as a consequence of transitioning to a more competitive industry, the nature of GRI funding is transitioning from mandatory FERC approved surcharges to voluntary contributions. We find the Company's proposed level of investment to be reasonable. We expect that the Company in managing its customers' dollars will choose to invest wisely in R&D

programs that will provide timely benefits to it and its customers. We find no reason to require that the Company submit the R&D program selected by it for Commission approval.

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The Commission finds Staff's proposed inclusion of the additional $72,671 FERC Docket RP-96-367 related credit in this tracker adjustment to be reasonable. The credit amount is known and measurable and should be factored as an offset into what is otherwise a sizeable PGA increase. Therefore, we reject the Company's proposal to defer allocation of this credit until next year's tracker.

Interest Adjustment ($15,885)

The Commission finds Staff's proposed interest adjustment to be reasonable. The Company contends that the over-refund (also FERC Docket RP-96-367) was a result of a miscalculation and that its customers have benefited from receipt of those monies. The Commission believes that this miscalculation was a result in part from the Company's contracting practice and relationship with IGI Resources, its affiliate. We encourage the Company to take appropriate steps to ensure that such confusion at the FERC level does not occur in the future.

Management Fees—IGI Resources

Staff challenges the reasonableness of the .005 MMBTU administrative fee paid by IGC to IGI Resources, Inc., rejects the nature of proof offered by IGC (e.g., CP National contract ending 1996; identified savings) and discounts the fee based on a comparison of relative risk in a similar Commission approved service contract between Avista Utilities and Avista Energy. Staff requests auditable documentation reflecting the cost to provide the service and/or a market evaluation showing verifiable current and independent market rates for the fee. Staff contends that the Company has not shown that the identified savings would not have been achieved by another marketer or in-house if Intermountain Gas had maintained their ability to do their own gas-related activities. The Company responds that it has no reason to believe that any other marketer could have achieved the same level of cost savings, reliability, and price stability that Resources has achieved.

The Commission finds that the developed record in this case provides no supportable basis for adjusting the administrative fee. The representations of the Company, while admittedly self-serving, have not been successfully rebutted. The IGC / IGI and Avista Utilities / Avista Energy contracts, we find are similar, but not equivalent. While Staff has made a best effort estimate in this case to distinguish and compare the nature of services provided under each contract, we find that an adjustment cannot be made without further information. The Commission recognizes that Intermountain Gas has historically served its gas customers well. The gas industry, however, is continuing to transition to a more competitive market. IGI Resources is no longer the sole marketer operating in IGC's service area. We caution the Company that it should not become complacent with its existing relationship with IGI. We direct the Company to develop a means of better verifying for itself and the Commission the cost savings that it attributes to its relationship with IGI Resources. The Company is also encouraged to periodically test the waters to determine whether other marketers have the ability to provide similar or better services at a competitive price. The Company's gas customers who remain captive and without choice are owed no less a duty of vigilance. In closing we remind the Company of the assurances that it gave to the Legislature in this most recent session regarding the Commission's access to affiliate records and our ability to deny affiliate expense.

Recognizing the changes that continue to occur in the industry, we direct Staff to conduct a study and report back to the Commission with its recommendations as to the continued reasonableness of the Company's PGA tracker.

The Commission has reviewed and considered the Company's Application in Case No. INT-G-99-1 together with the attached exhibits and workpapers. The Company in this case has requested a $9,637,020 increase in its annualized revenues. Based on our review and analysis, we find it appropriate, just and reasonable to approve the requested increase with the aforementioned adjustments for an authorized adjusted annual increase in revenue of $9,548,135 or 8.38%. We further find it reasonable that the change in rates and charges be implemented for an effective date of August 1, 1999. The Company is directed to file compliance tariffs conforming with this Order. Our approval includes the permanent adjustments, the temporary gas cost adjustments, surcharges and credits, and a balancing out of the Company's deferred PGA Account 186. We further agree that the changes should be tracked through to the customers as proposed in the Company's Application.

CONCLUSION OF LAW

The Idaho Public Utilities Commission has jurisdiction over this matter and Intermountain Gas Company, a gas utility, pursuant to the authority and power granted under Title 61 of the *Idaho Code* and the Commission's Rules of Procedure, IDAPA 31.01.01.000 *et seq.*

ORDER

In consideration of the foregoing and as more particularly described and qualified above, IT IS HEREBY ORDERED and Intermountain Gas Company is hereby authorized to change its rate and charges for RS-1, RS-2, GS-1 and LV-1/T-1/T-2 customers in the manner reflected in the Company's amended tariff sheets heretofore filed, with adjustments as described above for an effective date of implementation of August 1, 1999. The amended tariff sheets to be filed by the Company should comport with an authorized adjusted annual revenue requirement increase of $9,548,135 or 8.38%.

THIS IS A FINAL ORDER. Any person interested in this Order may petition for reconsideration within twenty-one (21) days of the service date of this Order. Within seven (7) days after any person has petitioned for reconsideration, any other person may cross-petition for reconsideration. See *Idaho Code* § 61-626.

DONE by Order of the Idaho Public Utilities Commission at Boise, Idaho this 30th day of July 1999.

DENNIS S. HANSEN, PRESIDENT

Commissioner Smith was out of the office on this date.

MARSHA H. SMITH, COMMISSIONER

PAUL KJELLANDER, COMMISSIONER

ATTEST:

Myrna J. Walters
Commission Secretary

vld/O:INT-G-99-1_sw3

Office of the Secretary
Service Date
July 30, 1999

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF INTERMOUNTAIN GAS COMPANY FOR AUTHORITY TO CHANGE ITS PRICES.	CASE NO. INT-G-99-1 ORDER NO. 28109

On May 14, 1999, Intermountain Gas Company (IGC; Company) filed an Application with the Idaho Public Utilities Commission (Commission) for authority to place into effect new rate schedules that would result in an overall increase of approximately $9.6 million in its annualized revenues. The increase reflects a change in the Company's cost of gas and the elimination and/or imposition of a number of temporary gas and transportation cost adjustments, surcharges and credits. The Company in its filing also proposes to balance out its Purchased Gas Cost Adjustment (PGA), Account 186. The PGA Account is a deferral mechanism for over- and under-collections and for realized savings on spot market gas purchases.

The proposed adjustments reflected in the Application include changes in costs billed IGC by Williams Gas Pipelines-West (WGP-W) and other transportation companies, the elimination of temporary surcharges and credits (INT-G-98-4), an increase in the Company's weighted average cost of gas (WACOG), the benefits generated from the Company's segmentation of its firm capacity rights on WGP-W's system, the inclusion of temporary surcharges and credits relating to gas and transportation related costs from the Company's deferred gas cost account (PGA Account 186), and an updated customer allocation of gas-related costs.

The Application proposes implementation of the following permanent and temporary changes, adjustments, surcharges and credits to IGC's tariff rates for natural gas service, sales and transportation:

Permanent Adjustments:

• INT-G-98-4 Elimination of Temporary Surcharges/Credits	($ 644,603)
• Change in WGP-W rates/charges	$1,963,300
• Change in storage costs	$ 457,385
• Cost of Gas Supply	$5,677,983

Temporary Surcharges or Credits

Deferred Gas Costs (IGC PGA Acct 186)

- NWP Refund Docket No. RP93-5 ($649,565)
- Variable Cost Collection Adjustment ($ 417,248)
- Uncollected Gas Costs $5,195,949
- Market Segmentation ($2,189,891)
- Storage credit ($ 465,603)
- Fixed Gas Cost Misc ($ 709,039)

As computed by the Company, the total requested increase in revenue on an annual basis is $9,637,020 or 8.46%. The net increase in sales gas revenues is $9,405,663 or 8.61%. The increase in T-1 transportation service revenues is $182,684 or 4.56%. The net increase in T-2 transportation service revenues is $48,673 or 6.52%. The annualized change in rates by class of service per Company calculation is as follows:

Gas Sales	Revenue	Avg Increase (Decrease) ¢/Therm	Avg Increase (Decrease) % Change	Proposed Avg Price $/Therm
RS-1 Residential	$1,212,193	3.416¢	5.66%	$0.63757
RS-2 Residential	$4,928,297	4.854¢	9.94%	$0.53698
GS-1 Genl Svc	$ 3,265,173	3.883¢	8.55%	$0.49323
LV-1 Large Vol. *				

* T-1 tariff price plus the Weighted Average Cost of Gas (WACOG), $0.18252

(Compare WACOG INT-G-98-4: $0.15684)

WACOG = total commodity cost of gas ÷ total purchase therms

Transportation	Revenue	Avg Increase (Decrease) ¢/Therm	Avg Increase (Decrease) % Change	Proposed Avg Price $/Therm
T-1 Transp.	$182,684	0.393¢	4.56%	$0.09003
T-2 Transp.	$ 48,673	0.224¢	6.52%	$0.03661

With the exception of the Industrial Class, IGC proposes to allocate the change in rates to each of its customer classes in accordance with its Purchased Gas Cost Adjustment tariff and approved cost-of-service methodology. (Ref. Case Nos. INT-G-95-1, INT-G-88-2, U-1034-137). Because there are no fixed costs currently recovered in the tailblock of IGC's T-1 tariff and because the proposed increase in the T-1 tariff is related to fixed costs (except for TF-1 commodity charge), a cents-per-therm increase is made only to the first two blocks of the T-1 tariff. All three blocks of IGC's proposed T-1 tariff have been adjusted to include WGP-W's firm transportation TF-1 commodity charge. The proposed increase in the T-2 tariff (except for TF-1 commodity charge) is fixed cost related and, therefore, a cents per therm increase was made only to the T-2 demand charge. The commodity charge component of the T-2 tariff was adjusted to include WGP-W's firm transportation TF-1 commodity charge.

Intermountain Gas requested that its Application be processed under Modified Procedure, i.e., by written submission rather that by hearing. Commission Notices of Application and Modified Procedure in Case No. INT-G-99-1 issued on June 4, 1999. The deadline for filing written comments was June 24, 1999. Reference Commission Rules of Procedure, IDAPA 31.01.01.201-204. Timely comments were filed by Commission Staff and six of the Company's customers. Three customer comments were filed out of time on June 25.

On July 1, 1999, the Commission in Case No. INT-G-99-1 issued Order No. 28087. The Company in its Application had requested an effective date of July 1, 1999. The Commission in its Order suspended the proposed July 1 effective date until August 1, 1999, making the following findings:

> We find, as the Company acknowledges, that Intermountain Gas has the affirmative burden of proof as to reasonableness regarding contract fees paid to its affiliate IGI Resources. Reference *Boise Water Corp v. Idaho*

> *PUC*, 97 Idaho 832, 555 P.2d 163 (1976). We note that the Company did not make such an offer of proof in its Application filing. It is only with the Company's filing of June 25th that we are provided with such offer of proof. The Commission finds that it needs more time to consider the Staff proposed "adjustments and Company responses."

Reference *Idaho Code* § 61-622.

The previously filed comments can be summarized as follows:

Customer Comments

The Company's customers object to the proposed increase, object to the inadequate notice provided by the Company and request a hearing. To grant the increase, one customer suggests, will eliminate the Company's incentive to reduce its external and internal expenses by eliminating inefficiencies. The size of the proposed increase is objected to by another customer who contends that it will create hardship among those of the elderly whose only income is social security. "What do we do," she queries, "when we can no longer pay the price to keep warm?"

An additional customer, Ms. Sharon Ullman, in comments filed June 24 requests that the Commission reconsider its Order No. 28068 and suspend the proposed July 1 effective date for at least 30 days and hold a public hearing or provide further opportunity for written comment and closer scrutiny of the Company's Application. Ms. Ullman notes that she did not receive the June 23 postmarked "customer notice" from IGC until June 24, the same day as the Commission deadline for filing written comments or protests. The Company notice, Ms. Ullman contends, is woefully inadequate. It is, she states, essentially a public relations document that says absolutely nothing to indicate that customer comments and/or protests are being accepted by the Commission.

Ms. Ullman in her letter also relates some frustration in her three attempts to obtain information from the Company's general manager of marketing and public relations, who, she states, instead of simply providing answers to questions regarding the Application, chose to question her with apparent suspicion about who she was and her interest in the case.

Ms. Ullman contends that by holding a public hearing in this case, or at the very least extending the public comment period, the Commission can help the public to understand that their circumstances, opinions and input are of concern to the Commission and that public input is welcomed and adequately sought.

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Management Fees—IGI Resources

Staff challenges the reasonableness of the .005 MMBTU administrative fee paid by IGC to IGI Resources, Inc., rejects the nature of proof offered by IGC (e.g., CP National contract ending 1996; identified savings) and discounts the fee based on a comparison of relative risk in a similar Commission approved service contract between Avista Utilities and Avista Energy. Staff requests auditable documentation reflecting the cost to provide the service and/or a market evaluation showing verifiable current and independent market rates for the fee. Staff contends that the Company has not shown that the identified savings would not have been achieved by another marketer or in-house if Intermountain Gas had maintained their ability to do their own gas-related activities. The Company responds that it has no reason to believe that any other marketer could have achieved the same level of cost savings, reliability, and price stability that Resources has achieved.

The Commission finds that the developed record in this case provides no supportable basis for adjusting the administrative fee. The representations of the Company, while admittedly self-serving, have not been successfully rebutted. The IGC / IGI and Avista Utilities / Avista Energy contracts, we find are similar, but not equivalent. While Staff has made a best effort estimate in this case to distinguish and compare the nature of services provided under each contract, we find that an adjustment cannot be made without further information. The Commission recognizes that Intermountain Gas has historically served its gas customers well. The gas industry, however, is continuing to transition to a more competitive market. IGI Resources is no longer the sole marketer operating in IGC's service area. We caution the Company that it should not become complacent with its existing relationship with IGI. We direct the Company to develop a means of better verifying for itself and the Commission the cost savings that it attributes to its relationship with IGI Resources. The Company is also encouraged to periodically test the waters to determine whether other marketers have the ability to provide similar or better services at a competitive price. The Company's gas customers who remain captive and without choice are owed no less a duty of vigilance. In closing we remind the Company of the assurances that it gave to the Legislature in this most recent session regarding the Commission's access to affiliate records and our ability to deny affiliate expense.

Recognizing the changes that continue to occur in the industry, we direct Staff to conduct a study and report back to the Commission with its recommendations as to the continued reasonableness of the Company's PGA tracker.

The Commission has reviewed and considered the Company's Application in Case No. INT-G-99-1 together with the attached exhibits and workpapers. The Company in this case has requested a $9,637,020 increase in its annualized revenues. Based on our review and analysis, we find it appropriate, just and reasonable to approve the requested increase with the aforementioned adjustments for an authorized adjusted annual increase in revenue of $9,548,135 or 8.38%. We further find it reasonable that the change in rates and charges be implemented for an effective date of August 1, 1999. The Company is directed to file compliance tariffs conforming with this Order. Our approval includes the permanent adjustments, the temporary gas cost adjustments, surcharges and credits, and a balancing out of the Company's deferred PGA Account 186. We further agree that the changes should be tracked through to the customers as proposed in the Company's Application.

CONCLUSION OF LAW

The Idaho Public Utilities Commission has jurisdiction over this matter and Intermountain Gas Company, a gas utility, pursuant to the authority and power granted under Title 61 of the *Idaho Code* and the Commission's Rules of Procedure, IDAPA 31.01.01.000 *et seq.*

ORDER

In consideration of the foregoing and as more particularly described and qualified above, IT IS HEREBY ORDERED and Intermountain Gas Company is hereby authorized to change its rate and charges for RS-1, RS-2, GS-1 and LV-1/T-1/T-2 customers in the manner reflected in the Company's amended tariff sheets heretofore filed, with adjustments as described above for an effective date of implementation of August 1, 1999. The amended tariff sheets to be filed by the Company should comport with an authorized adjusted annual revenue requirement increase of $9,548,135 or 8.38%.

THIS IS A FINAL ORDER. Any person interested in this Order may petition for reconsideration within twenty-one (21) days of the service date of this Order. Within seven (7) days after any person has petitioned for reconsideration, any other person may cross-petition for reconsideration. See *Idaho Code* § 61-626.

DONE by Order of the Idaho Public Utilities Commission at Boise, Idaho this 30th day of July 1999.

DENNIS S. HANSEN, PRESIDENT

Commissioner Smith was out of the office on this date.

MARSHA H. SMITH, COMMISSIONER

PAUL KJELLANDER, COMMISSIONER

ATTEST:

Myrna J. Walters
Commission Secretary

vld/O:INT-G-99-1_sw3

BASE RATE EXAMPLE

IL

STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

United Cities Gas Company	:	
	:	00-0228
Proposed general increase in gas rates.	:	
	:	

ORDER

By the Commission:

I. PROCEDURAL HISTORY

On February 17, 2000, United Cities Gas Company ("United Cities" or "Company"), a division of Atmos Energy Corporation, filed its Ill. C.C. No. 2, Original Title Sheet, Original Sheet Nos. 1 through 60 and an Original Information Sheet Supplemental to Sheet No. 59, hereinafter referred to as "Filed Rate Schedule Sheets," in which it proposed a general increase in gas rates, to be effective April 2, 2000.

Notice of the filing of the Filed Rate Schedule Sheets was posted in United Cities' business office and published in newspapers of general circulation throughout the Company's Illinois service area in accordance with the requirements of Section 9-201 of the Public Utilities Act ("Act"), 220 ILCS 5/1-101 et seq., and the provisions of 83 Ill. Adm. Code 255.

On March 15, 2000, the Commission entered an order suspending the Filed Rate Schedule Sheets to and including July 15, 2000. On July 6, 2000, the Commission resuspended the Filed Rate Schedule Sheets to and including January 15, 2001.

Pursuant to due notice, a pre-hearing conference was held in this matter before a duly authorized Hearing Examiner of the Commission at its offices in Springfield, Illinois on April 12, 2000. Thereafter, pursuant to due notice, a hearing was held at the Commission's Springfield offices on September 12, 2000. Appearances were entered by counsel on behalf of Commission Staff ("Staff") and United Cities. No petitions to intervene were filed in this proceeding. Mr. Mark Thessin, United Cities' Vice President, Rates and Regulatory Affairs, testified on behalf of United Cities. Mr. Thessin presented the Company's complete case including testimony regarding Company operations, rate base, operating statements, revenue requirements, rate design, cost of service study, and overall cost of capital for the Company's Illinois operations. In his rebuttal testimony, Mr. Thessin states that the Company and Staff resolved all issues of revenue requirement and rate design in this case. Staff presented the testimony of Ms. Mary Everson, an accountant in the Accounting Department of the Financial Analysis Division, who presented testimony showing Staff's adjusted operating statement and rate base and adjustments to the operating statement and rate base of the Company;

Mr. Thomas Smith, Accounting Supervisor in the Accounting Department of the Financial Analysis Division, who presented testimony proposing certain adjustments to the Company's operating statement and rate base; Ms. Burma Jones, an accountant in the Accounting Department of the Financial Analysis Division, who presented testimony proposing certain adjustments to the Company's operating statement and rate base; Ms. Janis Freetly, a financial analyst in the Finance Department of the Financial Analysis Division, who presented testimony as to the Company's capital structure, cost of capital, and rate of return on rate base; Ms. Terrie McDonald, an economic analyst in the Rate Department of the Financial Analysis Division, who presented testimony regarding cost of service and rate design; and Mr. Steven Cianfarini, a senior energy engineer in the Gas Section of the Energy Division, who presented testimony addressing certain technical issues regarding the Company's tariffs and rate base. Staff witnesses Smith and McDonald addressed the resolution of all issues in this case between Staff and the Company. At the conclusion of the hearing on September 12, 2000, the record was marked "Heard and Taken." The parties concluded at the hearing that briefs would not be necessary. United Cities filed a draft Order on September 19, 2000.

II. NATURE OF UNITED CITIES' OPERATIONS

United Cities, as a division of Atmos Energy Corporation, provides natural gas service to approximately 298,000 customers in Illinois and portions of six other states including Iowa, Missouri, Tennessee, Virginia, Georgia, and South Carolina. Atmos Energy Corporation, based in Dallas, Texas, provides natural gas to more than one million customers in 13 states through its operating divisions. Energas Company, Greeley Gas Company, Trans Louisiana Gas Company, United Cities Gas Company, Western Kentucky Gas Company, and United Cities Propane Gas.

The Company is headquartered in Franklin, Tennessee and provides natural gas service to approximately 25,000 customers in Illinois from four operating centers. These centers, in Virden, Vandalia, Harrisburg, and Metropolis, serve customers in Alma, Bluff City, Brookport, Carrier Mills, Cowden, Eldorado, Farmersville, Galatia, Girard, Harrisburg, Huey, Iuka, Joppa, Kinmundy, Metropolis, Middletown, Muddy, Naylor, Neelyville, New Holland, Quinlin, Raleigh, Salem, Thayer, Vandalia, Virden, Waggoner, and Xenia.

III. LAST RATE INCREASE

United Cities' last Illinois rate order was entered in Docket No. 96-0618 on June 25, 1997. In that proceeding, the Commission approved an increase in Illinois revenues of $427,671 or 2.09%. The Order authorized a rate of return on original cost rate base of 9.85%, which incorporated a return on common equity of 10.94%.

IV. UNITED CITIES' REASONS FOR THE PROPOSED RATE INCREASE

United Cities originally proposed an increase in annual revenues of $3,151,323 for the Illinois service area. Company Schedule A-3. As stated by Mr. Thessin in

UCGC Exhibit 6.0, the Company is accepting the revenue requirement as shown on ICC Staff Exhibit 7.0, Schedule 1.0, which results in an increase in annual revenues of $1,367,684, in order to resolve this case.

According to UCGC Exhibit 1.0, since the Company's last rate case in Docket No. 96-0618, it has made substantial investment in the areas of its Illinois service territory that have been newly acquired by the Company. In addition, United Cities states that it has made substantial investments in technology-based service and productivity improvements which are essential for operation of an efficient and high quality gas distribution system to meet future customer needs.

V. TEST YEAR

The Company's rate increase request is based on a pro forma historical test year, which ended September 30, 1999, with adjustments for purported known and measurable changes. Staff accepted the Company's use of this pro forma historical test year.

The Commission concludes that the test year, consisting of the 12 months ended September 30, 1999, with pro forma adjustments calculated in a manner consistent with the criteria set forth in Section 285.150 of 83 Ill. Adm. Code 285, is appropriate for the purposes of this proceeding.

VI. ORIGINAL COST RATE BASE

United Cities' proposed rate base was addressed in the Company's filing and in the testimony and schedules presented by Staff witnesses Mary Everson, Thomas Smith, Burma Jones, and Steven Cianfarini. In its testimony, the Company presented detailed evidence regarding its original cost rate base based on balances and costs for the 12 months ending September 30, 1999, with certain pro forma adjustments. Staff witnesses proposed certain adjustments to the Company's rate base. The Staff adjustments to rate base are reflected in ICC Staff Exhibit 7.0, Schedule 4. (See attached Appendices C and D.)

In her direct testimony, Staff witness Everson proposed the following adjustments to rate base: adjustments to Cash Working Capital for adjustments to operating expense items, allocation factor-rate base to correct an allocation factor, and quantified adjustments to plant in service to remove cost of retired LP plant and gas stored underground to correct an incorrect allocation of storage gas amounts. ICC Staff Exhibit 1.0. These adjustments were also proposed in rebuttal testimony Exhibit 7.0 except that the Cash Working Capital adjustment was modified to reflect operating expenses as proposed by Staff in its rebuttal testimony.

Staff witness Jones proposed the following adjustments to rate base: gas stored underground - provide a thirteen month average balance and remove inventory not available to Illinois customers; unamortized rate case expense - remove from rate base; unamortized Monarch Management Audit expense - remove from rate base; materials and supplies - provide a thirteen month average balance and remove materials and supplies associated with non-regulated operations; customer advances for construction - remove an allocation for advances outside of Illinois; customer deposits - correct Company's failure to recognize a normal level of customer deposits; budget billing advances - deduct from rate base. ICC Staff Exhibit 9.0.

Staff's adjustments were accepted by the Company in the resolution of this docket, as presented on ICC Staff Exhibit 7.0, Schedule 3.0 through Schedule 4.0, Page 2 of 2.

Based on the evidence, the Commission finds that the original cost rate base as shown in ICC Staff Exhibit 7.0, Schedule 3.0, Appendices C and D, is reasonable and should be accepted. Giving effect to the above finding, the Commission concludes that the Company's original cost rate base for the test year ended September 30, 1999 is as follows:

Utility Plant in Service	$ 38,189,688
Accumulated Depreciation	(17,399,227)
Net Plant	20,790,461
Additions to Rate Base:	
Construction Work in Progress	2,135,551
Gas Stored Underground	2,853,133
Gas Stored Underground-Cushion Gas	587,316
Consulting & Non-Compete Agreement	143,688
Materials and Supplies	388,702
Working Capital Allowance	533,221
Deductions from Rate Base:	
Customer Advances for Construction	(22,560)
Customer Deposits	(99,277)
Accumulated Deferred Income Taxes	(2,308,580)
Budget Billing Advances	(437,726)
Rate Base	$ 24,563,929

VII. OPERATING REVENUES, EXPENSES, AND INCOME

In its direct testimony and filing, United Cities presented detailed evidence regarding its operating revenues, expenses, and income for the test year ended September 30, 1999. In the testimony and schedules presented by ICC Staff witnesses Mary Everson, Thomas Smith, and Burma Jones, several adjustments to the Company's operating revenues, expenses, and income were proposed. Ms. Everson, in her direct testimony, made the following adjustments to operations expense: allocation factor-operating statement to correct an incorrect allocation factor, cost of gas to remove cost of purchased gas recovered through PGA, outside service contract to remove cost of a contract which does not benefit ratepayers, outside legal expense for cases not related to Illinois operations, and depreciation expense to correct an error in the Company's filing. ICC Staff Exhibit 1.0. These adjustments were also proposed in rebuttal testimony, ICC Staff Exhibit 7.0, except that Ms. Everson proposed an adjustment to Gas Research Institute ("GRI") cost to reflect a change in the method by which GRI bills utilities.

Ms. Jones in her direct testimony, proposed the following adjustments to operations expense: rate case expense amortization - adjust expense to reflect the unamortized balance of prior rate case expense when rates from this proceeding are expected to be in effect and to recognize a change in the Company's estimate of current rate case expense; Monarch Management Audit expense amortization - correct coding errors by the Company and reduce expense to reflect the unamortized balance when rates from this proceeding are expected to be in effect; memberships and dues - remove allocations for community organizations outside of Illinois; interest on customer deposits - coordinate with change to customer deposits; sales promotion expense - remove from test year; customer service expense - correct coding errors. ICC Staff Exhibit 3.0. In her rebuttal testimony, Ms. Jones reiterated these adjustments except that rate case expense was modified to reflect actual invoiced expense, and sales promotion expense was modified to reflect the nature of certain expenses included in this category. ICC Staff Exhibit 9.0.

Mr. Smith, in his direct testimony, proposed the following adjustments to operations expense: merger cost - to eliminate non-operating cost from revenue requirement; income tax - correct state tax rate; income tax - to reflect permanent book tax differences; pension cost - reverse Company adjustment to increase test year expense from negative to zero; forfeited discounts - to correct Company's failure to recognize a normal level of forfeited discounts; leases - to recognize a normal level of rent income; gas revenues - to eliminate the revenues used to recover gas costs from test year operating income; retired directors - to eliminate non-recurring cost; shared services - to eliminate non-recurring cost; payroll - to eliminate the Company's proposed adjustment because it is not known and measurable; benefits - to coordinate benefits with payroll; benefits - to reflect known and measurable conditions; and uncollectible expense - to reflect jurisdictional revenues. ICC Staff Exhibit 2.0. In rebuttal testimony, Mr. Smith proposed modifications to income tax expense to reflect proper allocation factors and to reflect the fact that certain expense items can not be deducted for income tax purposes. Other positions as reflected in direct testimony were retained in Mr. Smith's rebuttal testimony. ICC Staff Exhibit 8.0.

As part of the resolution of this Docket, the Company has accepted the operating revenues, expenses, and income as presented on ICC Staff Exhibit 7.0, Schedule 1.0 through Schedule 4.0, attached as Appendices A and B.

Based on all of the evidence of record in this proceeding, the Commission finds that the adjustments to the operating income statement as presented in ICC Staff Exhibit 7.0, Schedule 2.0, attached as Appendices A and B, are reasonable and should be adopted for ratemaking purposes in this proceeding. Upon giving effect to these adjustments and the rate of return on original cost rate base of 9.18% that is hereafter allowed in this Order, the Commission concludes that for purposes of this proceeding, United Cities' operating income statement for the test year ended September 30, 1999, at approved rates, is as follows:

Base Revenues	$9,224,540
Other Revenues	79,373
Total Operating Revenues	9,303,913
Uncollectible Accounts	242,864
Production	7
Storage	591
Transmission	2,356
Distribution	1,861,245
Customer Accounts	595,567
Customer Service	71,045
Sales Promotion	9,061
Administration and General	1,720,435
Interest on Customer Deposits	5,460
Depreciation and Amortization	1,746,460
Taxes Other than Income	217,630
Total Operating Expenses before Income Taxes	6,472,721
State Income Tax	104,145
Federal Income Tax	471,219
Total Operating Expenses	7,048,085
Net Operating Income	$2,255,828

The above operating income statement reflects the rate increase of $1,367,684 that is granted by this Order.

VIII. CAPITAL STRUCTURE, COST OF CAPITAL, AND RATE OF RETURN

The Company presented evidence regarding its capital structure and cost of capital in UCGC Exhibit 5.0. Staff presented evidence on these matters in the direct testimony of Janis Freetly. ICC Staff Exhibit 4.0. Each of these witnesses presented extensive analyses of the Company's capital structure and cost of capital.

The Company and Staff reached a settlement on the method of presenting the Company's capital structure and cost of capital in the Atmos Energy Corporation Universal Shelf Registration Docket No. 99-0687. The order in that docket was entered on September 7, 2000 and reads as follows:

> For its current rate case, ICC Docket No. 00-0228, Atmos will agree to use an imputed capital structure consisting of 67% total debt and 33% common equity. Atmos will agree to a cost of equity of 11.56%, as

calculated by Staff. The overall cost of capital is 9.18%, as calculated by the Staff. (Page 2, Order)

Based on the Order in Docket No. 99-0687 and the evidence contained in the testimony in this proceeding, the Commission finds that the capital structure and the cost of capital, including a cost of equity of 11.56% and an overall cost of capital of 9.18%, are supported by the evidence, are reasonable, and should be utilized in this proceeding. Accordingly, the Commission concludes that the fair rate of return on its common equity which the Company should be authorized to earn is 11.56%. United Cities capital structure and overall cost of capital approved herein are as follows:

	Ratio	Cost	Weighted Cost
Short Term Debt	15.28%	6.94%	1.061%
Long Term Debt	51.72%	8.33%	4.31%
Total Debt	67.00%		5.37%
Common Equity	33.00%	11.56%	3.81%
Total Capital	100.00		9.18%

The authorized return on equity of 11 56% will provide a return on original cost rate base of 9.18% under the capital structure herein approved. This rate of return will provide net operating income of $2,255,828 for United Cities. To earn this net operating income, a rate increase of $1,367,684 is required.

IX. COST OF SERVICE AND RATE DESIGN

Both the Company, through UCGC Exhibit 3.0, Schedule 1, and Staff, through the testimony of Terrie McDonald in ICC Staff Exhibit 5.0, Schedules 1.0, presented cost of service studies. Staff's cost of service study utilized the same basic methodologies which have been accepted by this Commission in the past. These cost of service studies included the same weather normalization techniques for sales and transport volumes.

The rate design for the various customer classes was discussed by the Company in UCGC Exhibits 3.0 and 6.0. Staff's rate design proposals were addressed by Terrie McDonald in both her direct and rebuttal testimony. ICC Staff Exhibit 5.0, Schedules 2.0 through 7.0 and ICC Staff Exhibit 10.0, Schedule 1.0. The rate design testimony includes discussions regarding elimination of Schedule 180 (Economic Development Gas Service), consolidation of Schedule 193 (Large Tonnage Air Conditioning Gas Service) with Schedule 192 (Cogeneration, Compressed Natural Gas, Prime Movers, Fuel Cell Service), and re-opening Schedule 150 (Optional Gas Service) to new customers. The Company and Staff have come to an agreement on the following rate design components for each customer class Schedule:

Schedule and Class Designation	Monthly Facilities Charge	Commodity Charge per CCF
Residential Gas Service, Schedule 110: All Zones	$ 9.90	$0.1939
Small Commercial and Small Industrial Gas Service, Schedule 120: All Zones	$ 25.00	$0.1521
Large Commercial and Large Industrial Gas Service, Schedule 130: All Zones	$100.00	$0.1415
Optional Gas Service, Schedule 150: All Zones	$100.00	$0.0499
Cogeneration, Compressed Natural Gas, Prime Movers, Fuel Cell Service, Large Tonnage Air Conditioning, Schedule 192: All Zones	$100.00	$0.0726

Based on the evidence, the Commission finds that the cost of service studies methodologies and rate design principles as embodied in the charges for the various customer class Schedules, as shown above and agreed to by the parties, are fully supported by the evidence, are reasonable, and should be adopted. The Commission further finds that the rate Schedules will produce the revenue requirement and operating income for United Cities found to be reasonable in this Order. Accordingly, the Commission finds that the rate Schedules are just and reasonable and should be approved, to become effective three days after filing.

X. SERVICE REGULATION AND OTHER ISSUES

The Company and Staff agree that the NSF check charge as currently presented on Ill. C.C. No. 1, Original Sheet No. 39 shall remain at $10.00.

The Company and Staff agree that there should be no separate meter and meter connection fee.

The Company and Staff agree that the Company should be allowed to read its meters once ever two months and that the following language should be included at the end of Paragraph 6.1 of the Company's Service Regulations: "All meters will be read at intervals of approximately 60 days."

The Company and Staff agree that the new Paragraph 6.3 in the Company's Service Regulations regarding re-reading charges should state:

> If at any time the customer questions the accuracy of the meter reading, the customer can request the Company to read the meter. After such re-read, if the original meter reading was accurate, within 5%, the customer shall be warned that they could be charged $35.00 to compensate the Company for the expense of conducting future readings if the customer requests re-reads which do not result in an adjusted bill more than 3 times in a 12 month period. The Company shall inform the customer of the charge prior to re-reading the meter the 4th time in one 12 month period. Should the original meter reading be in error, over 5% high, the customer shall not be charged the fee and the appropriate billing adjustments shall be made.
>
> However, if the customer habitually requests (more than 3 times in a 12 month period) a meter re-read which does not result in an adjusted bill, then the customer shall be charged the $35.00 fee.

The Company and Staff agree that language should be added at the end of Paragraph (1)(d), Section d of the Company's Service Regulations that reads, "with the exception of any charges related to GRI contributions." This change reflects the offset to the inclusion of GRI contributions in the Company's base revenues.

The Company and Staff agree that it is in the Company's and Illinois customers' best interests that a depreciation study be performed on the Company's utility plant impacting Illinois customers prior to the Company's next rate case filing.

The Company and Staff agree that the Company should change its service extension policy to allow the Company to offer 60 feet of service line (an increase of 100%) to customers installing gas space heating equipment and 40 feet of service line (a decrease of 20%) to customers installing a gas water heater. In addition, the Company and Staff agree that the Company should change its service extension policy to allow the Company to offer a maximum of 100 feet of service line (down from 150 feet) to non-residential customers with estimated annual consumption of 100 Mcf or less. The agreement regarding service extension policy is based on the economics of new construction costs of service lines.

Based on the evidence, the Commission concludes that setting the NSF check charge at $10.00, not having a separate meter and meter connection fee, permitting meter readings once ever two months, the re-read charge language, additional language reflecting the exclusion of GRI costs from the PGA calculation, and the agreement by the Company to perform a depreciation study are reasonable and should be approved. In addition, the Commission concludes, based on the evidence, that the changes to the Company's service extension policy are reasonable and should be approved.

The Company and Staff agree that the Company should change current tariff sheets 2, 27, 28, 32, 34, 38, and 47. On those sheets, the Company makes reference to "General Orders." Those references should be changed to the appropriate Administrative Code Parts

XI. FINDINGS AND ORDERING PARAGRAPHS

The Commission, having given due consideration to the entire record herein and being fully advised in the premises, is of the opinion and finds that:

(1) United Cities is a corporation organized and existing under and by virtue of the laws of the State of Texas and Commonwealth of Virginia, is duly authorized to conduct business as a foreign corporation within the State of Illinois, is engaged in the business of rendering natural gas service to the public in the State of Illinois, and is a Public Utility as defined by the Act;

(2) the Commission has jurisdiction over United Cities and the subject matter herein;

(3) the recitals of fact and conclusions reached in the prefatory portion of this Order are supported by the evidence and are hereby adopted as findings of fact;

(4) for purposes of this proceeding, the test year is a historical pro forma test year ending September 30, 1999, such test year is appropriate for purposes of this proceeding;

(5) for purposes of this proceeding, United Cities original cost rate base is $24,563,929;

(6) for purposes of this proceeding, United Cities' revenue requirement is $9,303,913;

(7) a just and reasonable rate of return which United Cities should be allowed to earn on its original cost rate base is 9.18%; this rate of return incorporates a reasonable return on common equity of 11.56%;

(8) the rates of return set forth in Finding (7) hereinabove result in operating revenues of $9,303,913 for United Cities and net operating income of $2,255,828; to earn this operating income, an increase in operating revenues of $1,367,684 or 17.23% is required for United Cities;

(9) United Cities rates which presently are in effect are insufficient to generate the operating income necessary to permit the Company to earn a just and reasonable return; the Company rates which are presently in effect should be permanently canceled and annulled;

(10) the proposed rates filed by United Cities would produce a rate of return in excess of that which is fair and reasonable; the Company proposed rates as filed should be permanently canceled and annulled;

(11) the evidence demonstrates that the currently proposed rates will produce the revenue requirement, operating income, and rate of return on rate base discussed in Findings (6), (7), and (8) above, are designed in accordance with the cost of service and rate design guidelines approved in the prefatory portion of this Order, and are agreed to by the interested parties;

(12) the rates and charges as proposed are just and reasonable;

(13) United Cities should file new tariff sheets setting forth the rates and charges provided for in this Order, within 10 days of the date of this Order, said tariff sheets to be effective for all service rendered on and after three days after filing;

(14) United Cities should maintain its NSF check charge at $10.00; be allowed to read its meters once every two months; not have a separate meter and meter connection fee; institute the re-read policy and charge set forth above, exclude GRI costs from its PGA calculation; and perform a depreciation study prior to its next rate case filing; in addition, the changes in the Company's service extension policy are reasonable and should be approved;

(15) all motion and objections made in this proceeding that remain undisposed of should be disposed of in a manner consistent with the ultimate conclusions herein.

IT IS THEREFORE ORDERED by the Illinois Commerce Commission that the tariffs presently in effect for gas service rendered by United Cities Gas Company are hereby permanently canceled and annulled effective at such time as the new gas tariff sheets approved herein become effective by virtue of this Order for all service rendered on or after three days after filing.

IT IS FURTHER ORDERED that the proposed tariffs filed as Ill. C.C. No. 2 seeking a general increase in gas rates in United Cities Gas Company's Illinois service area, filed by the Company on February 17, 2000, are hereby permanently canceled and annulled.

IT IS FURTHER ORDERED that the Suspension Order entered on March 15, 2000 and Resuspension Order entered on July 6, 2000, are hereby vacated and set aside in so far as they relate to United Cities Gas Company.

IT IS FURTHER ORDERED that United Cities Gas Company is hereby authorized and directed to file new tariff sheets in accordance with the Commission's findings and conclusions herein.

IT IS FURTHER ORDERED that United Cities Gas Company shall comply with Finding (14) of this Order.

IT IS FURTHER ORDERED that United Cities Gas Company shall complete a depreciation study prior to its next rate case filing before this Commission for the utility ~~plant used in the provision of service to its Illinois customers.~~

IT IS FURTHER ORDERED that any motions or objections in this proceeding that remain undisposed are hereby disposed of in a manner consistent with the ultimate conclusions contained herein.

IT IS FURTHER ORDERED that subject to the provisions of Section 10-113 of the Public Utilities Act and 83 Ill. Adm. Code 200.880, this Order is final; it is not subject to the Administrative Review Law.

By order of the Commission this 18th day of October, 2000.

(SIGNED) RICHARD L. MATHIAS

Chairman

(S E A L)

Docket No 00-0228
Appendix A

United Cities Gas Company
Statement of Operating Income with Adjustments
For the Test Year Ended September 30, 1999
(In Dollars)

Line No	Description (A)	Company Pro Forma Present (Sch 1, p. 2) (B)	Staff Adjustments (Sch 2) (C)	Staff Pro Forma Present (Cols. B+C) (D)	Company Proposed Increase (Source) (E)	Staff Gross Revenue Conversion Factor (F)	Proposed Rates with Staff Adjustments (Cols. D+E+F) (G)	Adjustment To Proposed Increase (H)	Staff Pro Forma Proposed (Cols. G+H) (I)	Revenue Change (Col I-D) (J)	% Revenue Change (3) (K)
1	Base Revenues	$ 17,730,695	$ (9,873,839)	$ 7,856,856	$ 3,151,323	$ (4,335)	$ 11,003,844	$ (1,779,304)	$ 9,224,540		
2	Other Revenues	45,576	33,797	79,373	-	-	79,373	-	79,373		
3	Total Operating Revenue	17,776,271	(9,840,042)	7,936,229	3,151,323	(4,335)	11,083,217	(1,779,304)	9,303,913	$ 1,367,684	17 23%
4											
5	Uncollectible Accounts	233,017	-	233,017	-	22,658	255,675	(12,811)	242,864		
6	Production	9,873,840	(9,873,839)	7	-	-	7	-	7		
7	Storage	591	-	591	-	-	591	-	591		
8	Transmission	2,356	-	2,356	-	-	2,356	-	2,356		
9	Distribution	1,861,245	-	1,861,245	-	-	1,861,245	-	1,861,245		
10	Customer Accounts	595,567	-	595,567	22,690	(22 690)	595,567	-	595,567		
11	Customer Service	70,225	820	71,045	-	-	71,045	-	71,045		
12	Sales Promotion	25,170	(16,109)	9,061		-	9,061		9,061		
13	Administration and General	2,635,570	(915,135)	1,720,435	-	-	1,720,435	-	1,720,435		
14	Interest on Customer Deposits	3,342	2,118	5,460	-	-	5,460	-	5 460		
15	Depreciation and Amortization	1,776,123	(29,663)	1,746,460	-	-	1,746,460	-	1,746,460		
16	Taxes other than Income	217,630	-	217,630	-	-	217,630	-	217,630		
17	Total Operating Expense										
18	Before Income Taxes	17,294,682	(10,831,808)	6,462,874	22,690	(32)	6,485,532	(12 811)	6,472,721		
19											
20	State Income Tax	(37,159)	43,811	6,652	228,390	(4,063)	230,979	(126,834)	104,145		
21	Federal Income Tax	(165,155)	195,254	30,099	1,015,241	(240)	1,045,100	(573,881)	471,219		
22	Deferred Taxes and ITCs Net	-	-	-	-	-	-	-	-		
23	Total Operating Expenses	17,092,368	(10,592,743)	6,499,625	1,266,321	(4,335)	7,761,611	(713,526)	7,048,085		
24											
25	NET OPERATING INCOME	$ 683,903	$ 752,701	$ 1,436,604	$ 1,885,002	$ -	$ 3,321,606	$ (1,065,778)	$ 2,255,828		
26	Staff Rate Base								$ 24,563,929 (1)		
27	Staff Overall Rate of Return								9 18% (2)		

(1) Source Staff Exhibit 1 0, Schedule 3, Page 1, Column (D)
(2) Source. Staff Exhibit 4 0, Schedule 12 0.
(3) Source Column (J), Line 3, divided by Column (D), Line 3

United Cities Gas Company
Adjustments to Operating Income
For the Test Year Ended September 30, 1999
(In Dollars)

Line No	Description (A)	Interest Synchron-ization (St Ex 7 0 Sched 6.0) (B)	Allocation Factor- Op Expense (St. Ex 7.0 Sched 10.0) (C)	Depreciation Exp -LP Plant (St Ex 7 0 Sched 11.0) (D)	Cost of Gas (St Ex 7 0 Sched 12.0) (E)	Outside Services Contract (St Ex 7 0 Sched 13.0) (F)	Outside Legal Expense (St Ex 7 0 Sched 14.0) (G)	Depreciation Expense (St. Ex 7 0 Sched 15.0) (H)	Merger Cost (St. Ex 8 0 Sched 1.0) (I)	Income Tax Expense (St Ex 8 0 Sched 2.0) (J)	Subtotal (K)
1	Base Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Other Revenues	-	-	-	-	-	-	-	-	-	-
3	Total Operating Revenue	-	-	-	-	-	-	-	-	-	-
4											
5	Uncollectible Accounts	-	-	-	-	-	-	-	-	-	-
6	Production	-	-	-	-	-	-	-	-	-	-
7	Storage	-	-	-	(9,873,839)	-	-	-	-	-	(9,873,839)
8	Transmission	-	-	-	-	-	-	-	-	-	-
9	Distribution	-	-	-	-	-	-	-	-	-	-
10	Customer Accounts	-	-	-	-	-	-	-	-	-	-
11	Customer Service	-	-	-	-	-	-	-	-	-	-
12	Sales Promotion	-	-	-	-	-	-	-	-	-	-
13	Administration and General	-	-	-	-	(4,030)	(2,691)	-	(628,427)	-	(635,148)
14	Interest on Customer Deposits	-	-	-	-	-	-	-	-	-	-
15	Depreciation and Amortization	-	(35,310)	(5,029)	-	-	-	10,676	-	-	(29,663)
16	Taxes other than Income	-	-	-	-	-	-	-	-	-	-
17	Total Operating Expense										
18	Before Income Taxes	-	(35,310)	(5,029)	(9,873,839)	(4,030)	(2,691)	10,676	(628,427)	-	(10,538,650)
19											
20	State Income Tax	(23,561)	2,535	361	708,942	289	193	(787)	45,121	(3,836)	729,277
21	Federal Income Tax	(106,604)	11,471	1,634	3,207,714	1,309	874	(3,468)	204,157	(20,334)	3,296,753
22	Deferred Taxes and ITCs Net	-	-	-	-	-	-	-	-	-	-
23	Total Operating Expenses	(130,165)	(21,304)	(3,034)	(5,957,183)	(2,432)	(1,624)	6,441	(379,149)	(24,170)	(6,512,620)
24											
25	NET OPERATING INCOME	$ 130,165	$ 21,304	$ 3,034	$ 5,957,183	$ 2,432	$ 1,624	$ (6,441)	$ 379,149	$ 24,170	$ 6,512,620

United Cities Gas Company
Adjustments to Operating Income
For the Test Year Ended September 30, 1999
(In Dollars)

Line No	Description (A)	Subtotal (L)	Pension Expense (St Ex 8 0 Sched 6.0) (M)	Forfeited Discounts (St Ex 8 0 Sched 7.0) (N)	Lease Revenue (St Ex 8 0 Sched 8.0) (O)	Gas Sales Revenue (St Ex 8 0 Sched 9.0) (P)	Director Retirement (St Ex 8 0 Sched 10.0) (Q)	Shared Services (St Ex 8 0 Sched 11.0) (R)	Payroll Expense (St Ex 8 0 Sched 12.0) (S)	Benefits Expense (St Ex 8 0 Sched 13.0) (T)	Subtotal (U)
1	Base Revenues	$ -	$ -	$ -	$ -	$ (9,873,839)	$ -	$ -	$ -	$ -	$ (9,873,839)
2	Other Revenues	-	-	24,457	9,340	-	-	-	-	-	33,797
3	Total Operating Revenue	-	-	24,457	9,340	(9,873,839)	-	-	-	-	(9,840,042)
4											
5	Uncollectible Accounts	-	-	-	-	-	-	-	-	-	-
6	Production	(9,873,839)	-	-	-	-	-	-	-	-	(9,873,839)
7	Storage	-	-	-	-	-	-	-	-	-	-
8	Transmission	-	-	-	-	-	-	-	-	-	-
9	Distribution	-	-	-	-	-	-	-	-	-	-
10	Customer Accounts	-	-	-	-	-	-	-	-	-	-
11	Customer Service	-	-	-	-	-	-	-	-	-	-
12	Sales Promotion	-	-	-	-	-	-	-	-	-	-
13	Administration and General	(635,148)	(139,497)	-	-	-	(8,010)	(19,309)	(11,141)	(25,844)	(838,949)
14	Interest on Customer Deposits	-	-	-	-	-	-	-	-	-	-
15	Depreciation and Amortization	(29,663)	-	-	-	-	-	-	-	-	(29,663)
16	Taxes other than Income	-	-	-	-	-	-	-	-	-	-
17											
18	Total Operating Expense										
19	Before Income Taxes	(10,538,650)	(139,497)	-	-	-	(8,010)	(19,309)	(11,141)	(25,844)	(10,742,451)
20											
21	State Income Tax	729,277	10,016	1,756	671	(708,942)	575	1,386	800	1,856	37,395
22	Federal Income Tax	3,296,753	45,318	7,945	3,034	(3,207,714)	2,602	6,273	3,619	8,396	156,226
23	Deferred Taxes and ITCs Net	-	-	-	-	-	-	-	-	-	-
24	Total Operating Expenses	(6,512,620)	(84,163)	9,701	3,705	(3,916,656)	(4,833)	(11,650)	(6,722)	(15,592)	(10,538,830)
25											
26	NET OPERATING INCOME	$ 6,512,620	$ 84,163	$ 14,756	$ 5,635	$ (5,957,183)	$ 4,833	$ 11,650	$ 6,722	$ 15,592	$ 698,788

United Cities Gas Company
Adjustments to Operating Income
For the Test Year Ended September 30, 1999
(In Dollars)

Line No	Description (A)	Subtotal (V)	Uncollectible Accounts Expense (St Ex 8 0 Sched 14.0) (W)	Rate Case Amort. (St. Ex 9 0 Sched 8.0) (X)	Monarch Mgmt Audit Exp Amortization (St Ex 9 0 Sched 9.0) (Y)	Memberships & Dues (St. Ex 9 0 Sched 10.0) (Z)	Interest on Customer Deposits (St Ex 9 0 Sched 11.0) (AA)	Sales Promotion Expense (St Ex 9 0 Sched 12.0) (AB)	Customer Service Expense (St Ex 9 0 Sched 13.0) (AC)	GRI Expense (St Ex 7.0 Sched 17.0) (AD)	Total Operating Statement Adjustments (AE)
1	Base Revenues	$ (9,873,839)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (9,873,839)
2	Other Revenues	33,707	-	-	-	-	-	-	-	-	33,707
3	Total Operating Revenue	(9,840,042)	-	-	-	-	-	-	-	-	(9,840,042)
4											
5	Uncollectible Accounts	-	-	-	-	-	-	-	-	-	-
6	Production	(9,873,839)	-	-	-	-	-	-	-	-	(9,873,839)
7	Storage	-	-	-	-	-	-	-	-	-	-
8	Transmission	-	-	-	-	-	-	-	-	-	-
9	Distribution	-	-	-	-	-	-	-	-	-	-
10	Customer Accounts	-	-	-	-	-	-	-	-	-	-
11	Customer Service	-	-	-	-	-	-	-	820	-	820
12	Sales Promotion	-	-	-	-	-	-	(16,109)	-	-	(16,109)
13	Administration and General	(838,949)	(131,641)	12,370	2,274	(1,189)	-	-	-	42,000	(915,135)
14	Interest on Customer Deposits	-	-	-	-	-	2,118	-	-	-	2,118
15	Depreciation and Amortization	(29,663)	-	-	-	-	-	-	-	-	(29,663)
16	Taxes other than Income	-	-	-	-	-	-	-	-	-	-
17	Total Operating Expense										
18	Before Income Taxes	(10,742,451)	(131,641)	12,370	2,274	(1,189)	2,118	(16,109)	820	42,000	(10,831,808)
19											
20	State Income Tax	37,395	9,452	(888)	(163)	85	(152)	1,157	(59)	(3,016)	43,811
21	Federal Income Tax	166,226	42,766	(4,019)	(739)	386	(688)	5,233	(266)	(13,645)	195,254
22	Deferred Taxes and ITCs Net	-	-	-	-	-	-	-	-	-	-
23	Total Operating Expenses	(10,538,830)	(79,423)	7,463	1,372	(718)	1,278	(9,719)	495	25,339	(10,592,743)
24											
25	NET OPERATING INCOME	$ 698,788	$ 79,423	$ (7,463)	$ (1,372)	$ 718	$ (1,278)	$ 9,719	$ (495)	$ (25,339)	$ 752,701

Docket No 00-0228
Appendix C

United Cities Gas Company
Rate Base
For the Test Year Ended September 30, 1999
(In Dollars)

Line No	Description (A)	Company Pro Forma (Sch B-1) (B)	Staff Adjustments (Sch 4.0) (C)	Staff Pro Forma (Col B+C) (D)
1	Utility Plant in Service	$ 38,903,289	$ (713,601)	$ 38,189,688
2	Accumulated Depreciation	(17,863,772)	464,545	(17,399,227)
3	Net Plant	21,039,517	(249,056)	20,790,461
4				
5	Additions to Rate Base			
6	Construction work in progress	2,163,418	(27,867)	2,135,551
7	Gas stored underground	3,340,790	(487,657)	2,853,133
8	Gas stored underground-Cushion Gas	59,965	527,351	587,316
9	Consulting and non-compete agreement	143,688	-	143,688
10	Unamortized rate case expense	185,573	(185,573)	-
11	Unamort Monarch management audit	14,195	(14,195)	-
12	Materials and supplies	282,520	106,182	388,702
13	Working capital allowance	678,386	(145,165)	533,221
14		-	-	-
15		-	-	-
16				
17	Deductions from Rate Base.			
18	Customer advances for construction	(18,931)	(3,629)	(22,560)
19	Customer deposits	(60,765)	(38,512)	(99,277)
20	Accumulated deferred income taxes	(2,492,808)	184,228	(2,308,580)
21	Budget billing advances	-	(437,726)	(437,726)
22		-	-	-
23		-	-	-
24		-	-	-
25		-	-	-
26				
27	Rate Base	$ 25,335,548	$ (771,619)	$ 24,563,929

Docket No 00-0228
Appendix D
Page 1 of 2

United Cities Gas Company
Adjustments to Rate Base
For the Test Year Ended September 30, 1999
(In Dollars)

Line No	Description (A)	Allocation Factor-Rate Base (St Ex 7 0 Sched 9.0) (B)	LP Plant (St Ex 7 0 Sched 11.0) (C)	Gas Stored Underground (St Ex 9 0 Sched 1.0) (D)	Unamortized Rate Case Expense (St Ex 9 0 Sched 2.0) (E)	Unamortized Monarch Mgmt Audit (St Ex 9 0 Sched 3.0) (F)	Materials & Supplies (St Ex 9 0 Sched 4.0) (G)	Customer Adv for Construction (St Ex 9 0 Sched 5.0) (H)	Customer Deposits (St Ex 9 0 Sched 6.0) (I)	Budget Billing Advances (St Ex 9 0 Sched 7.0) (J)	Subtotal (K)
1	Utility Plant in Service	$ (411,532)	$ (302,069)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (713,601)
2	Accumulated Depreciation	162,476	302,069	-	-	-	-	-	-	-	464,545
3	Net Plant	(249,056)	-	-	-	-	-	-	-	-	(249,056)
4											
5	Additions to Rate Base										
6	Construction work in progress	(27,867)	-	-	-	-	-	-	-	-	(27,867)
7	Gas stored underground	-	-	(487,657)	-	-	-	-	-	-	(487,657)
8	Gas stored underground-Cushion Gas	-	-	-	-	-	-	-	-	-	-
9	Consulting and non-compete agreement	-	-	-	-	-	-	-	-	-	-
10	Unamortized rate case expense	-	-	-	(185,573)	-	-	-	-	-	(185,573)
11	Unamort Monarch management audit	-	-	-	-	(14,195)	-	-	-	-	(14,195)
12	Materials and supplies	-	-	-	-	-	106,182	-	-	-	106,182
13	Working capital allowance	-	-	-	-	-	-	-	-	-	-
14		-	-	-	-	-	-	-	-	-	-
15		-	-	-	-	-	-	-	-	-	-
16		-	-	-	-	-	-	-	-	-	-
17	Deductions from Rate Base:										
18	Customer advances for construction	-	-	-	-	-	-	(3,629)	-	-	(3,629)
19	Customer deposits	-	-	-	-	-	-	-	(38,512)	-	(38,512)
20	Accumulated deferred income taxes	184,228	-	-	-	-	-	-	-	-	184,228
21	Budget billing advances	-	-	-	-	-	-	-	-	(437,726)	(437,726)
22		-	-	-	-	-	-	-	-	-	-
23		-	-	-	-	-	-	-	-	-	-
24		-	-	-	-	-	-	-	-	-	-
25		-	-	-	-	-	-	-	-	-	-
26		-	-	-	-	-	-	-	-	-	-
27	Rate Base	$ (92,695)	$ -	$ (487,657)	$ (185,573)	$ (14,195)	$ 106,182	$ (3,629)	$ (38,512)	$ (437,726)	$ (1,153,805)

United Cities Gas Company
Adjustments to Rate Base
For the Test Year Ended September 30, 1999
(In Dollars)

Line No	Description (A)	Subtotal (L)	Cash Working Capital (St Ex 7 0 Sch 8.0) (M)	Gas Stored Underground-Cushion Gas (St Ex 7 0 Sch 16.0) (N)	(Source) (O)	(Source) (P)	(Source) (M)	(Source) (R)	(Source) (S)	(Source) (T)	Subtotal (U)
1	Utility Plant In Service	$ (713,601)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (713 601)
2	Accumulated Depreciation	464,545	-	-	-	-	-	-	-	-	464,545
3	Net Plant	(249,056)	-	-	-	-	-	-	-	-	(249,056)
4											
5	Additions to Rate Base										
6	Construction work in progress	(27,867)	-	-	-	-	-	-	-	-	(27,867)
7	Gas stored underground	(487,657)	-	-	-	-	-	-	-	-	(487,657)
8	Gas stored underground-Cushion Gas	-	-	527,351	-	-	-	-	-	-	527,351
9	Consulting and non-compete agreement	-	-	-	-	-	-	-	-	-	-
10	Unamortized rate case expense	(185,573)	-	-	-	-	-	-	-	-	(185,573)
11	Unamort Monarch management audit	(14,195)	-	-	-	-	-	-	-	-	(14,195)
12	Materials and supplies	106,182	-	-	-	-	-	-	-	-	106,182
13	Working capital allowance	-	(145,165)	-	-	-	-	-	-	-	(145,165)
14		-	-	-	-	-	-	-	-	-	-
15		-	-	-	-	-	-	-	-	-	-
16											
17	Deductions from Rate Base:										
18	Customer advances for construction	(3,629)	-	-	-	-	-	-	-	-	(3,629)
19	Customer deposits	(38,512)	-	-	-	-	-	-	-	-	(38,512)
20	Accumulated deferred income taxes	184,228	-	-	-	-	-	-	-	-	184,228
21	Budget billing advances	(437,726)	-	-	-	-	-	-	-	-	(437,726)
22		-	-	-	-	-	-	-	-	-	-
23		-	-	-	-	-	-	-	-	-	-
24		-	-	-	-	-	-	-	-	-	-
25		-	-	-	-	-	-	-	-	-	-
26											
27	Rate Base	$ (1,153,805)	$ (145,165)	$ 527,351	$ -	$ -	$ -	$ -	$ -	$ -	$ (771,619)

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COMMONWEALTH OF KENTUCKY
PUBLIC SERVICE COMMISSION
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Paul E. Patton
Governor

Ronald B. McCloud, Secretary
Public Protection and
Regulation Cabinet

Helen Helton
Executive Director
Public Service Commission

December 29, 1999

W Ky Gas

Delta NG

Tina Thomas
Gas Research Institute
Suite 900
1600 Wilson Boulevard
Arlington, Virginia 22209

Dear Ms. Thomas:

On April 29, 1999, the Commission held a meeting in its offices to discuss with affected parties the future funding of the Gas Research Institute ("GRI") in Kentucky in light of the Federal Energy Regulatory Commission ("FERC") decision to phase out mandatory collection of GRI charges by interstate pipelines. The meeting was attended by the major Kentucky LDCs, the Attorney General's office, representatives of GRI, and members of the Commission and Staff.

Since voluntary funding of GRI by LDCs first became an issue, the Commission has received two proposals for recovery of such funding. In Case No. 97-066-F, Delta Natural Gas Company proposed to continue GRI funding at the last FERC-approved level for full mandatory funding, and collect it through its Gas Cost Adjustment ("GCA") mechanism. The Commission did not approve the voluntary amount to be flowed through as gas cost, pending a thorough review of the subject. In Delta's pending rate case, Case No. 99-176, it did not offer an alternative proposal on its own to continue GRI funding, but indicated it would not be averse to a tariff rider method of collecting GRI funding from customers.

Subsequently, in Case No. 99-070, the Commission approved a settlement agreement among Western Kentucky Gas and other parties to the case pursuant to which Western will, among other things, implement a GRI tariff rider.

The Commission has in the past approved the inclusion of expenses related to Research and Development ("R&D") in revenue requirements. Such expenses, approved as part of base rates, were required to be supported and justified in terms of benefits to the utility and ratepayers. Tariff rider mechanisms for such purpose require the same justification in terms of costs and benefits. Funding used for the purpose of

Tina Thomas
December 22, 1999
Page 2

such activities as lobbying and advertising will likely be treated as it has in the past, by being excluded from recovery. Moreover, even though the Commission's decision in Case No. 99-070 indicates its acceptance of tariff rider mechanisms for recovery of GRI contributions, the burden of proving that the recovery is reasonable will remain, as always, on the utility proposing such a mechanism. It should also be noted that the Commission's acceptance of the Western Kentucky Gas tariff rider mechanism does not indicate that approval of other such filings will be automatic; nor does that acceptance indicate that GRI has been designated by the Commission as a sole source provider of R&D in Kentucky.

As a final matter, a utility wishing to propose R&D funding recovery by including it in a base rate proceeding as part of its revenue requirement remains at liberty to do so.

Sincerely,

Helen C. Helton

Helen C. Helton
Executive Director

wc

IN THE MATTER OF THE APPLICATION OF KANSAS GAS SERVICE, A DIVISION OF ONEOK, INC., FOR ADJUSTMENT OF ITS NATURAL GAS RATES IN THE STATE OF KANSAS.	) DOCKET NO. 03-KGSG-602-RTS

STAFF DIRECT TESTIMONY

PREPARED BY

JEFFREY D. MCCLANAHAN

UTILITIES DIVISION

KANSAS CORPORATION COMMISSION STAFF

Q. Please state your name and business address.

A Jeffrey D McClanahan, 1500 SW Arrowhead Road, Topeka, Kansas

Q. Who is your employer and what is your title?

A I am employed by the Kansas Corporation Commission ("Commission" or "KCC") as the Chief of Accounting and Financial Analysis

Q. What is your educational background and professional experience?

A I hold a B A in Accounting from West Texas State University I was employed for approximately eight years by a Savings and Loan institution in professional positions in auditing and accounting I joined the KCC in December 1997 as a Utility Auditor II I was promoted to Senior Auditor in May 1998 and was subsequently promoted to my present position in February 2002

Q. Have you previously testified before the Commission?

A Yes, I have filed testimony in numerous dockets before the Commission

Q. What is the purpose of your testimony?

A The purpose of my testimony is to introduce the Staff witnesses, address Kansas Gas Service's ("KGS") proposed Home Energy Low-Income Program Rider ("HELPR") tariff rate, and address the proposed Gas Technology Institute ("GTI") pass-through tariff

Q. Please provide a list of Staff witnesses and a description of the testimony they are sponsoring.

A A list of Staff witnesses is presented below

__Bill Baldry__ Staff witness Baldry provides recommendations regarding KGS's revenues and operating expenses

__Dr. John Cita__ Staff witness Cita discusses KGS's weather normalization adjustment, WeatherProof Bill, flex tariffs, and the proposed HELPR tariff Dr Cita also proposes an adjustment to KGS's weather normalization adjustment

__David N. Dittemore__ Staff witness Dittemore is a consultant working on behalf of Staff Mr Dittemore provides recommendations regarding KGS's proposed transfer of the Mid-Continent Marketing Center ("MCMC") assets back to KGS, Corporate Cost allocations, and operating statement adjustments

__Adam Gatewood__ Staff witness Gatewood provides an analysis of KGS's cost of equity capital and recommends an appropriate capital structure

__Larry Holloway__ Staff witness Holloway provides recommendations regarding KGS's proposed transfer of the MCMC assets back to KGS

Dr. Soojong Kwak Staff witness Kwak sponsors Staff's weather normalization adjustment and customer annualization adjustments to KGS's test year natural gas sales for selected rate classes

Michael J. Majoros, Jr.: Mr Majoros is a consultant working on behalf of Staff and the Citizens Utility Ratepayer Board ("CURB") Mr Majoros has conducted a depreciation study and is recommending new depreciation rates for KGS

Jeff McClanahan I provide an overview of Staff's testimony and address KGS's proposed HELPR tariff and the proposed GTI tariff

Ryan Mulvany Staff witness Mulvany provides testimony sponsoring adjustments to KGS's rate base and operating statement Mr Mulvany also sponsors Staff's revenue requirement schedules

Dorothy Myrick Staff witness Myrick sponsors testimony regarding KGS's rate design

James M. Proctor Staff witness Proctor is a consultant working on behalf of Staff Mr Proctor sponsors testimony regarding KGS's general corporate cost allocation factor and employee pension, medical, and post-retirement benefit expenses Mr Proctor also addresses interest synchronization

Philip T. Sanchez: Staff witness Sanchez sponsors testimony regarding KGS's General Terms and Conditions, Sales Service Rate Schedules, Transportation Service Rate Schedules, and the Cost of Gas Rider

Justin Watkins Staff witness Watkins sponsors testimony regarding KGS's flexible tariff agreements and proposes related adjustments

Duzel Yates: Staff witness Yates sponsors testimony regarding KGS's operating income statement and proposes related adjustments Mr Yates also provides background information on the current rate case

HELPR Tariff

Q. What is the proposed HELPR tariff?

A KGS has proposed a tariff which would provide discounts to eligible customers in the amount of 50% of the Residential Service tariff and 50% of Delivery Charges The 50% reductions would not apply to the cost of gas paid by the eligible customers As proposed, the discount afforded to the eligible customers would be spread to all remaining customers, except discount customers, on a per Mcf basis Eligible customers would be defined as those customers qualifying under the federally-funded Low Income Energy Assistance Program ("LIEAP") KGS has quantified the impact of the program as affecting approximately 13,000 customers with an annual discount of approximately $1,972,109 KGS witness Mr Larry Willer addresses the HELPR program at pages 6 and 7 of his testimony.

Q. What is Staff's position regarding the HELPR program?

A Staff's legal counsel has reviewed the legality of the proposed program and determined that the HELPR program appears to meet the definition of a lifeline rate The Commission previously concluded that it is legally prohibited from implementing targeted lifeline rates because they are unduly discriminatory [Docket No 134,584-U, Order issued November 9, 1982 at pp 7-8] Staff's position on the legality of this issue will be fully outlined in its post-hearing brief

Q. How does KGS's proposed HELPR program meet the definition of a lifeline rate?

A It is my understanding that Docket No 134,584-U defined a lifeline rate as

> a rate set below the cost of service so as to assist a certain group of consumers in meeting their essential needs and/or to promote some general public interest A lifeline rate is one made available to a selected group of consumers, based not upon their utility usage characteristics, but upon socio-economic factors such as, age, income or handicap The purpose of such a rate is to help those consumers who for whatever reason, are unable to afford the cost of their essential energy needs [Order at p 2]

KGS's proposed HELPR tariff is set below the cost of service so as to assist a certain group of consumers, based not upon their utility usage characteristics, but upon socio-economic factors

Q. Is Staff proposing an alternative methodology to KGS'S HELPR program?

A Not within the context of this docket Staff witness Myrick discusses the HELPR program further in her testimony and recommends a separate investigation to determine how to implement a low-income tariff. In addition, Staff witness Cita discusses the HELPR program.

GTI Tariff

Q. Please explain what GTI is, and provide some background on the organization.

A. The Gas Research Institute ("GRI") is the predecessor to GTI. GTI is a non-profit consumer benefits research and development ("R&D") organization. GTI's research currently focuses on six areas that were agreed upon in a settlement at the Federal Energy Regulatory Commission ("FERC"). These areas are (1) increased gas supply from emerging resources, (2) improved gas system reliability and integrity, (3) lowered operating and maintenance costs, (4) increased efficiency of use, (5) enhanced environmental quality, and (6) enhanced health and safety.[1] KGS witness Ronald Edelstein discusses GTI's R&D programs and the related surcharge in his testimony.

Q. What is the GTI tariff?

A. KGS has proposed including a surcharge of $0.0174 per Mcf on the Cost of Gas Rider ("COGR") in order to fund its participation in the R&D conducted by the GTI. KGS has estimated the total annual cost to its ratepayers at approximately $1.5 million. GTI is currently funded through a FERC-approved surcharge on gas transported over interstate pipelines. Therefore, KGS customers have been

[1] *See*, Staff Exhibit JDM-1, p. 6 of 21 and JDM-2, p. 3 of 33

indirectly supporting GTI through upstream gas prices FERC has decided to eliminate the surcharge at the end of 2003 and transition support for GTI to a voluntary basis

Q. How was the $0.0174 per Mcf surcharge determined?

A It is unclear to Staff how the $0 0174 per Mcf surcharge was originally determined While the surcharge was approved by FERC, Staff cannot find a specific notation or calculation stating the total dollar amount to be collected or the budget year(s) on which the surcharge was based[2] It does appear that GTI had a FERC-approved refund mechanism for over-collections of its targeted funding levels However it is unclear how, or if, the refund mechanism is intended to be used in the future

Q. Is Staff opposed to the GTI surcharge?

A Generally speaking, no Staff is supportive of R&D that benefits KGS's customers Therefore, Staff is interested in the possible benefits that may be obtained for KGS's customers from GTI However, Staff does have a number of concerns related to the GTI proposal

Q. What are Staff's concerns?

A Staff's concerns are noted below.

[2] *See*, FERC Opinion No 418, Docket No RP97-149-002, p 17

1 The information provided in KGS's application only outlines GTI's benefits for customers KGS does not outline how it, or GTI, envisions the role of the Commission in participating, reviewing, and approving future R&D projects In addition, KGS does not discuss how future surcharges are to be calculated and reviewed by the Commission Staff requested KGS provide its vision for future R&D program years in Staff Data Request No 459[3] KGS responded to Data Request No 459 by stating, in part

> KGS would anticipate letting the Commission know annually what R&D projects it selected for funding *It is anticipated that the R&D surcharge would be effective until KGS filed to change it* [Emphasis added]
>
> KGS, and the Commission through oversight, will have full rights to select each and every R&D project it wishes to fund or to not fund There are no mandatory projects All parties funding projects will have approval input Parties not funding projects would have no input approval

Clearly, KGS has not outlined a detailed review process for the Commission to follow In addition, since the surcharge is a pass-through from KGS to GTI, KGS will not have any money at risk Therefore KGS will most likely transfer most of the burden of supporting the surcharge in the future to GTI, a nonjurisdictional entity

[3] *See*, Staff Exhibit JDM-3, p 3 of 4

Staff asked that KGS provide a detailed narrative explaining the benefits its ratepayers will receive from participation in GTI in Staff Data Request No 460[4] KGS responded by stating

> Benefits to ratepayers from KGS'S participation in GTI's voluntary programs are expected to include (1) O&M cost savings from the use of horizontal boring tools, keyhole excavation equipment, advanced shoring techniques, and similar projects, (2) enhanced safety due to plastic pipe lifetime estimation tools, coatings accelerated testing, pipeline integrity, indoor air quality, and advanced leak detection and plastic pipe location equipment, (3) lower energy bills due to high-efficiency residential dehumidification, water heating, and space heating technology, and lower demand due to increased efficiency commercial cooling and industrial burner and combustor technology

Based on KGS's response, it does not appear that the potential ratepayer savings have been quantified Staff believes that a quantification of the expected savings is important in order for the Commission to evaluate the costs and benefits of this proposal

2 As stated previously, Staff is unsure as to how the proposed $0 0174 per Mcf surcharge was determined Staff is concerned that neither KGS nor GTI has provided evidence regarding how future surcharges will be determined The FERC has stated that " In seeking the resolution of the issue of long-term GRI funding, the Commission continues to be guided by the underlying objective of ensuring stable GRI funding while spreading the responsibility for funding the R&D sponsored by GRI as

[4] *See,* Staff Exhibit JDM-3, p 4 of 4

evenly as possible over the broadest base of natural gas service "[5] KGS and GTI have not outlined the anticipated timeline to seek approval from each State's public utility commission, and the possible impact of future surcharge rates In addition, KGS and GTI have not addressed whether they intend to pass any over-collections back through the COGR Staff maintains that these issues need to be addressed

3 Staff is concerned that other gas utilities will request a GTI surcharge, and a piecemeal approach will be taken to reviewing the applications This may lead to inconsistencies in the review and approval process for the Commission For example, Atmos Energy has also proposed a GTI surcharge in its recently filed rate case, Docket No 03-ATMG-1036-RTS Atmos' application provides essentially the same support for its requested surcharge as KGS It appears to Staff that it is only a matter of time before most, if not all, KCC jurisdictional gas utilities request a GTI surcharge

Q. What is Staff's recommendation regarding the GTI surcharge?

A Staff recommends a separate investigation regarding the GTI surcharge As stated previously, Staff supports R&D and GTI may well benefit KGS's customers However, Staff does not believe that KGS or GTI have provided enough evidence on how the R&D programs will be reviewed, how often the

[5] *See*, Opinion 418, issued November 12, 1997, in Docket Nos RP97-149-002, RP97-391-000, and RM97-3-00, p 9

review process will occur, how surcharges will be determined, and the appropriate means of dealing with any over collections In addition, a separate investigation will enable Staff and the Commission to be consistent in the review and approval process for R&D programs in which KCC jurisdictional utilities participate

Q. What issues should be addressed in such a general investigation?

A The issues addressed should include, but not necessarily be limited to, the following

1. How often should the Commission review and approve the R&D programs?
2. Should the Commission be able to select R&D programs that Kansas gas utilities participate in, or just have input?
3. How will future surcharges be determined?
4. Should the amount of money collected through the surcharge be capped at a predetermined level?
5. What support should be required for the calculation of surcharges?
6. What support should be required to demonstrate that KGS is paying its fair share of support for GTI based on its participation level with GTI?
7. Should the benefits to KGS's customers be quantified? If so, how often?
8. If the benefits to gas customers do not exceed the contributions to GTI in a particular year, how long should GTI and Kansas gas utilities be given to demonstrate a benefit before consideration is given to eliminating the surcharge?

9 Should over collections be passed back through the COGR?

10 Should reports be filed with the Commission? If so, what areas should be addressed (*e g*, R&D progress reports and related total cost) and how often should the reports be submitted?

11 Should all gas customers participate?

12 Should all utilities participate?

Q When should the Commission begin the separate investigation?

A Due to current workload considerations, Staff is recommending that the separate investigation be initiated late 2003 at the earliest However, Staff recognizes that the investigation will not be completed prior to KGS's requested date of January 1, 2004 Therefore, Staff is recommending that KGS be allowed to use the FERC approved surcharge of $0 0174 per Mcf through 2004 However, in order to prevent an over collection, the total amount collected should be capped either at KGS's estimated cost of approximately $1 5 million or at some other amount that can be supported on the record by KGS or GTI This option will allow Staff, GTI, and the Commission more time to thoroughly investigate the proposal

Q. Does this complete your testimony?

A Yes, it does

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of

ADJUSTMENT OF GAS RATES OF COLUMBIA GAS OF KENTUCKY, INC	))	CASE NO 2002-00145

ORDER

In its Order approving the merger of Columbia Energy Group ("Columbia Energy") and NiSource, Inc ("NiSource"), the Commission required the Chief Executive Officers ("CEO") of both utilities to commit that Columbia Gas of Kentucky, Inc ("Columbia") would "[f]ile by the earlier of September 30, 2002 or 18 months after consummation of the merger, a rate case including the statutory filing requirements, a cost-of-service study, an estimate of future net merger savings, and a mechanism to reflect on ratepayers' bills future merger savings and the net deferred merger savings "[1] To comply with the CEOs' commitments, Columbia filed its application on May 1, 2002 for authority to adjust its gas rates to produce additional annual revenues of $2,503,221, an increase of 2 3 percent [2]

BACKGROUND

Columbia, a wholly-owned subsidiary of Columbia Energy, is a Kentucky corporation regulated by the Commission as a utility under KRS 278 010(3)(b). It is engaged in the business of selling and distributing natural gas, as well as the

[1] Case No 2000-00129, Joint Application of NiSource, Inc , New NiSource Inc , Columbia Energy Group and Columbia Gas of Kentucky for Approval of a Merger, Order Issued June 30, 2000

[2] Application at 3

transportation of customer-owned volumes of gas[3] Columbia provides gas service to approximately 141,000 retail customers within the Commonwealth of Kentucky

PROCEDURE

Columbia submitted written notice of its intent to file an application for an adjustment of rates on April 1, 2002 and subsequently tendered its application on May 1, 2002 Columbia requested to place its proposed rates into effect on June 1, 2002 To determine the reasonableness of the proposed rates, the Commission issued an Order on May 21, 2002 suspending the proposed rates for 5 months from their effective date, pursuant to KRS 278 190(2), up to and including October 31, 2002

The following parties requested and were granted full intervention the Attorney General of the Commonwealth of Kentucky, by and through his Office of Rate Intervention, the Kentucky Industrial Utility Customers, Inc , the Lexington-Fayette Urban County Government, the Kentucky Association for Community Action, and the Community Action Council for Lexington-Fayette, Bourbon, Nicholas and Harrison Counties, Inc (collectively "Intervenors")

On May 21, 2002, the Commission issued a procedural schedule to investigate Columbia's rate application The schedule provided for discovery, intervenor testimony, rebuttal testimony by Columbia, a public hearing, and an opportunity for the parties to file post-hearing briefs

JOINT STIPULATION AND RECOMMENDATION

Pursuant to a request by Columbia, an informal conference was scheduled and held on September 12, 2002 at the Commission's offices in Frankfort, Kentucky At the

[3] Application at 1

conference, Columbia and the Intervenors informed Commission Staff ("Staff") that they had been negotiating a settlement and that their discussions were ongoing Although a settlement had not been reached, they wanted to advise the Commission of the status of their settlement discussions The parties stated that they planned to continue settlement discussions and would advise the Commission if they reached a settlement

Pursuant to a second request by Columbia, an informal conference was scheduled and held on September 19, 2002 at the Commission's offices in Frankfort, Kentucky At the September 19, 2002 conference, Columbia and the Intervenors informed Staff that their settlement negotiations had been successful and that they anticipated filing a formal settlement agreement and supporting testimony with the Commission by September 27, 2002

On October 2, 2002, Columbia and the Intervenors filed their Joint Stipulation and Recommendation ("Joint Stipulation"), which is attached hereto and incorporated herein as Appendix B Included with the Joint Stipulation was the supporting Direct Testimony of Joseph W Kelly, Executive Vice President and Chief Operating Officer of Columbia The following is a brief synopsis of the Joint Stipulation

1 Columbia will reduce its base rates by an amount that results in a decrease to its annual operating revenues of $7,800,000 The reduction in Columbia's base rates will be effective for service rendered on and after March 1, 2003

2 Columbia's proposed tariff revisions are modified as follows (a) the proposed margin loss recovery rider is withdrawn, (b) the proposed merger savings rider is withdrawn, (c) the Inland rate schedules on Tariff Sheet Nos 26 through 29 will be cancelled, (d) the proposed changes to the service line extension policy on Tariff

Sheet No 62 should be implemented, and (e) the change to the definition of the term "gas day" on Tariff Sheet No 100 should be implemented

3 Columbia will withdraw the proposed funding mechanism for the Energy Assistance Program ("EAP"), but will retain the proposed EAP to be funded by customers via a surcharge with a true-up for actual cost recovery and by an annual contribution from Columbia's shareholders of $175,000 The EAP will initially operate as a continuation of the current Customer Assistance Program ("CAP") until the EAP program details are agreed upon by the parties, or October 1, 2003, whichever occurs first The EAP will be effective with Columbia's second billing cycle following the issuance of the Commission's Order approving the Joint Stipulation The EAP surcharge will be calculated to generate $500,000 for the program budget plus a true-up for the prior year

4. Columbia will fund the Gas Technology Institute ("GTI") at $300,000 per year by means of a line item accounting, which shall include a true-up to prevent over- or under-recovery. The GTI surcharge will be recovered from all distribution customers except those served under the Alternative Fuel Displacement Service or the flex rate provisions of the Delivery Service rate schedule

5 Columbia will implement new depreciation rates using the average service life procedure and the remaining life basis The depreciation rates are set forth in Attachment B of the Joint Stipulation

6 The Direct Testimony of Columbia witness Jeffery T Gore dealing with the treatment of other post-retirement employee benefits ("OPEB") is accepted with the

following modifications (a) Columbia will continue to amortize its OPEB transition obligation pursuant to the stipulation approved in Columbia's last rate case, and (b) Columbia will reclassify the entire OPEB gain of $1,966,111 as a regulatory asset and amortize the gain over the remaining life of the original transition period

7 Columbia will withdraw its proposal to fund, and to implement at this time, the Automated Meter Reading Program ("AMRP") Columbia will continue to consider implementation of an AMRP as a part of its normal review of budgets and capital expenditures

8 Columbia will not be required to make post-merger filings set forth in Case No 2000-00129 that duplicate Columbia's SEC fillings The filings that are duplicative are set out in Columbia's January 30, 2001 filing in Case No 2000-00129

MODIFICATION TO JOINT STIPULATION

On October 14, 2002, Staff issued its Post-Settlement Data Request to Columbia and the Intervenors In their respective responses all Parties state either that they agree to or that they do not oppose several of Staff's recommended modifications to the Joint Stipulation The following is a brief synopsis of those modifications

1 The stipulated service line extension policy on Tariff Sheet No 62 should be modified to reflect (a) the following definition of major source of energy, "A customer's major source of energy is defined as its primary energy source for heating the premises", (b) an effective date of March 1, 2003, and (c) Columbia will file the 2002 average cost for a service line extension with the Commission as Tariff Sheet No 62a at least 30 days prior to the March 1, 2003 date and will update the average cost of such extensions annually by making similar fillings in subsequent years

2 The EAP program described on Tariff Sheet No 51b should be modified to reflect (a) that it is effective on March 1, 2003, and (b) that revised Tariff Sheet No 51b reflecting the new surcharge rate will be filed at least 30 days prior to the effective date

3 Columbia will begin accumulating funds for its EAP program in March 2003 for disbursements that will begin in November 2003

4 Tariff Sheet No 51b will note that the EAP surcharge will be a separate line item on customers' bills

ASSESSMENT OF THE JOINT STIPULATION AND THE MODIFICATIONS

Columbia and the Intervenors agree that the Joint Stipulation is reasonable and in the best interest of all concerned Therefore, they urge the Commission to accept this Joint Stipulation in its entirety While the overall reasonableness of the Joint Stipulation is an important factor, the Commission is bound by law to act in the public interest and review all elements of the Joint Stipulation 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 Joint Stipulation as modified is unanimous and that the participation of the Intervenors ensures that a wide range of interests were represented The Intervenors have been involved in previous Columbia rate proceedings and are well aware of the issues involved in the current proceeding

The Joint Stipulation set forth only the amount of revenue decrease agreed to and not the underlying calculations and adjustments In determining the overall reasonableness of the proposed $7,800,000 decrease in Columbia's annual operating revenues, the Commission has evaluated Columbia's and the Intervenors' proposed adjustments to capital, rate base, operating revenues, and operating expenses in light of our normal rate-making treatment In addition, consideration has been given to the rates of return on common equity authorized by the Commission in recent rate cases Based on a review of all these factors and the evidence of record, the Commission finds that the earnings resulting from the Joint Stipulation should fall within a range reasonable for both Columbia and its ratepayers The $7,800,000 revenue decrease provided for in the Joint Stipulation will result in fair, just, and reasonable rates for Columbia

Based upon a review of all aspects of the Joint Stipulation as modified, an examination of the record, and being otherwise sufficiently advised, the Commission finds that the Joint Stipulation as modified is in the public interest and should be approved The Commission's approval of this settlement is based solely on its reasonableness in toto and does not constitute the approval of any rate-making adjustment or revenue allocation

While the Commission would prefer for Columbia's shareholders to fund 50 percent of the EAP, as they did for the CAP, we are encouraged by Columbia's commitment to provide a substantial level of shareholder funding to the program The Commission hopes that other utilities under its jurisdiction will take note and choose to follow Columbia's example

IT IS THEREFORE ORDERED that

1 The rates and charges proposed by Columbia in its application are denied

2 The rates and charges in Appendix A are approved for service rendered by Columbia on and after March 1, 2003

3 The tariff changes and additions included in the Joint Stipulation as modified herein are approved effective March 1, 2003

4 Columbia shall file its revised Tariff Sheet No 62a, the average cost for a service line extension, its revised Tariff Sheet No 51b reflecting the new EAP surcharge rate, and supporting documentation, at least 30 days prior to the effective date of March 1, 2003

5 Columbia shall file a report, as a supplement to the annual report submitted with the Commission, outlining the previous year's projects funded by its GTI surcharge

6 At least 30 days prior to their effective dates, Columbia shall file its revised tariff sheets setting out the rates and tariffs approved herein for service rendered on and after March 1, 2003

Done at Frankfort, Kentucky, this 13th day of December, 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 2002-00145 DATED December 13, 2002

The following rates and charges are prescribed for the customers in the area served by Columbia Gas of Kentucky, Inc All other rates and charges not specifically mentioned herein shall remain the same as those in effect under authority of this Commission prior to the effective date of this Order

	Base Rate Charge	Gas Cost Adjustment Demand	Gas Cost Adjustment Commodity	Total Billing Rate
SCHEDULE GSR				
First 1 Mcf or less per mo	$6 95	$1 7923	$2 9893	$11 7316
Over 1 Mcf per mo	1 8715	1 7923	2 9893	6 6531
RATE SCHEDULE GSO				
Commercial or Industrial				
First 1 Mcf or less per mo	18 88	1 7923	2 9893	23 6616
Next 49 Mcf per mo	1 8715	1 7923	2 9893	6 6531
Next 350 Mcf per mo	1 8153	1 7923	2 9893	6 5969
Next 600 Mcf per mo	1 7296	1 7923	2 9893	6 5112
Over 1000 Mcf per mo	1 5802	1 7923	2 9893	6 3618
Delivery Service				
Administrative Charge	55 90			55 90
Standby Service Demand Charge				
Demand Charge Times Daily Firm Vol (Mcf) In Customer Service Agreement		8 6481		8 6481
Delivery Rate Per Mcf				
First 400 Mcf per mo	1 8153			1 8153
Next 600 Mcf per mo	1 7296			1 7296
All Over 1000 Mcf per mo	1 5802			1 5802
Former IN8 Rate	1 0575			1 0575
Banking and Balancing Service		0 0211		0 0211

SCHEDULE GPR

First 1 Mcf or less per mo	6 95	NA	NA	NA
Over 1 Mcf per mo	1 8715	NA	NA	NA

RATE SCHEDULE GPO

Commercial or Industrial				
First 1 Mcf or less per mo	18 88	NA	NA	NA
Next 49 Mcf per mo	1 8715	NA	NA	NA
Next 350 Mcf per mo	1 8153	NA	NA	NA
Next 600 Mcf per mo	1 7296	NA	NA	NA
Over 1000 Mcf per mo	1 5802	NA	NA	NA

RATE SCHEDULE IS

Customer Charge per mo	116 55			116 55
First 30,000 Mcf	5467		2 9893	3 5360
Over 30,000 Mcf	2905		2 9893	3 2798
Standby Service Demand Charge				
Demand Charge Times Daily Firm Vol (Mcf) in Customer Service Agreement		8 6481		8 6481
Delivery Service				
Administrative Charge	55 90			55 90
First 30,000 Mcf	5467			5467
Over 30,000 Mcf	2905			2905
Banking and Balancing Service		0 0211		0 0211

RATE SCHEDULE IUS

For All Volumes Delivered Each Month	3038	1 7923	2 9893	5 0854
Delivery Service				
Administrative Charge	55 90			55 90
Delivery Rate per Mcf	3038	1 7923	2 9893	5 0854
Banking and Balancing Service		0 0211		0 0211

MAINLINE DELIVERY SERVICE

Administrative Charge	55 90			55 90
Delivery Rate per Mcf	0 0858			0 0858
Banking and Balancing Service		0 0211		0 0211

RATE SCHEDULE SVGTS	Delivery Change per Mcf
General Service Residential	
First 1 Mcf or less per month	$6 95 (Minimum Bill)
Over 1 Mcf per month	1 8715
General Service Other	
First 1 Mcf or less per month	$18 88 (Minimum Bill)
Next 49 Mcf per month	1 8715
Next 350 Mcf per month	1 8153
Next 600 Mcf per month	1 7296
Over 1000 Mcf per month	1 5802
Intrastate Utility Service	
For all volumes per month	$0 3038
Actual Gas Cost Adjustment	
For all volumes per month	$0 2553

APPENDIX B

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO 2002-00145 DATED December 13, 2002

See 200200145apx_121302 pdf

Western Kentucky Gas Company

MEMORANDUM

WESTERN KENTUCKY GAS

TO: Atmos Rate Council, Tina Thomas - GRI

FROM: Bill Senter *Bill Senter*

DATE: June 23, 1999

SUBJECT: GRI R&D Unit Charge Rider

Enclosed is a copy of the GRI R&D Unit Charge Rider filed by Western in its recent rate case, KPSC Case No. 99-070. I am also including the relevant testimony filed by Gary Smith, VP - Marketing pertaining to our GRI proposal. The tariff was based upon sample tariff language provided by GRI, which is also enclosed.

Please advise if you have any questions, 270-685-8072.

Enclosures

Atmos Rate Council:

Tom Hawkins
Mark Thessin
Ben Boyd
Christine Tabor
Bill Guy
John Hack
Tom Petersen
Doug Walther
Tom Stephens

864-2806

Xc: JoAnn Smith

WESTERN KENTUCKY GAS COMPANY

Gas Research Institute R & D Rider

GRI R & D Unit Charge

(N)

Application:
This rider applies to the distribution charge applicable to all gas transported by the Company other than Rate T-3 and T-4 Carriage Service.

GRI R&D Unit Charge:
The intent of the Gas Research Institute R&D Unit Charge is to maintain the Company's level of contribution per Mcf as of December 31, 1998. The Unit Charge will be billed according to the transition schedule outlined in the pipelines' tariffs.

Waiver Provision:
The GRI R&D Unit Charge may be reduced or waived for one or more classifications of service or rate schedules at any time by the Company by filing notice with the Commission.

Remittance of Funds:
All funds collected and this rider will be remitted to Gas Research Institute on a monthly basis The amounts so remitted shall be reported to the Commission annually.

Reports to the Commission:
A statement setting forth the manner in which the funds remitted have been invested in research and development will be filed with the Commission annually.

Termination of this Rider: Participation in the GRI R&D funding program is voluntary on the part of the Company This rider may be terminated at any time by the Company by filing a notice of recision with the Commission.

Q. Is the result the same to ratepayers?

A. Yes, but under a zero-based GCA, it is easier for the customer to see that the gas charge recovers gas costs and that the distribution charge recovers margin.

Q. Are there any other benefits to a zero-based GCA?

A. Yes, there are several. First, some confusion will be removed from the bill because it will no longer show a correction factor (gas cost amount). On a given month, this line item could be either positive or negative and is an essentially meaningless subtotal in the GCA calculation process – and, provides no beneficial information on the costs of gas to the customer. Secondly, the GCA also becomes easier to calculate once separated out from the embedded cost of gas. Thirdly, a zero-based GCA is a small, but first step toward retail gas choice. It is important during the transition toward unbundling that customers understand which costs will be subject to choice and which would remain embedded in our cost of service. A zero-based GCA better informs customers of the different costs of providing gas.

Q. Do any other gas companies regulated by this Commission have zero-based GCA's.

A. Yes, Columbia Gas for one

Q Do any other Atmos companies have zero-based GCA's?

A. Yes, most of the 11 other states in which Atmos operates allow zero-based GCA's

Q. Please describe the phased-in restructuring of collecting Gas Research Institute (GRI) Research and Development (R&D) surcharge as proposed by Western.

A. Consistent with the settlement reached at the Federal Energy Regulatory Commission (FERC), interstate pipelines are phasing-out the billing of GRI R&D surcharge to local distribution companies like Western. As a result of this settlement, GRI will lose all of its funding by the year 2004 unless LDCs, in cooperation with their state regulatory commissions, establish alternative funding mechanisms to pick-up the difference Western's proposal is to fully fund GRI in its rates consistent with its December 31, 1998 level of GRI R&D surcharge recovery.

Q How will Western phase in its restructured collection of GRI costs?

A. Today, the GRI R&D surcharge is recovered through the GCA because it is billed a component of gas cost from the pipeline. Since pipelines will no longer include the GRI R&D surcharge per the FERC settlement, we will no longer bill these to the customer as gas costs. After discussions with representatives of GRI and the Commission, we have decided to go ahead in this case and directly fund the GRI R&D surcharge as a component of our distribution charge applicable to all gas sold and transported, other than Carriage Services Rate T-3 and Rate T-4. All funds collected under this rider will be remitted to GRI on a monthly basis. We will continue to collect the pipeline billed GRI R&D surcharge as gas costs during the transition to full direct funding by Western. The restructuring will be complete after 2004.

Q. When would Western propose to adjust its GRI R&D collections?

A Western would propose to adjust it GRI R&D collections annually consistent with the GRI R&D surcharge level being collected through the pipelines as of December 31, 1998, in conjunction with the transition schedule outlined in the pipelines' tariffs

Q. Please describe Western's proposed Margin Loss Recovery Rider.

A. The Margin Loss Recovery Rider is designed to keep Western largely whole when industrial margins are reduced as a result of contracts negotiated to avoid bypass. Our proposal will shift most but not all lost revenue to the Company's sales service customers Western would retain a portion of the loss associated with a renegotiated contract as an incentive for Western to maximize contract revenues through the highest possible negotiated price.

Q Please explain the risk sharing proposed by Western.

A. Our proposal is for a 90/10 sharing of the risk of negotiated contracts. Western will adjust the volumetric commodity rate of all sales customers by an amount equal to 90 percent of the associated annual revenue reduction, while absorbing the remaining 10 percent of the revenue reduction as an incentive.

MAR-2-00 12:13PM; Page 1/2

Post-it® Fax Note 7671	Date 3-3-2000	# of pages 2
To Tina Thomas	From Ron Snedic	
Co./Dept. GRI	Co. GRI-SGM	
Phone #	Phone # 972 620 4019	
Fax # 703 526 7805	Fax #	

Western Kentucky Gas Company

WESTERN KENTUCKY GAS

February 29, 2000

Mr. Ron Snedic
Gas Research Institute
3030 LBJ Freeway
Suite 1300
Dallas, TX 75234

Subject: Western Kentucky Gas Company Rate Case No. 99-070
GRI Research & Development Unit Surcharge Rider

Dear Ron,

The Compliance tariffs filed last month in response to the Commission's Order in our rate case are in effect. As promised, I am attaching the final approved GRI R&D Rider tariff page for WKG in Kentucky

Our GRI rates are different from those of the pipelines' GRI transition schedules because we have statewide rates, we are served by multiple pipelines, we buy at different volumes/rate schedules, and we were at different stages of "GRI discounts" from some of them in December 1998. These approved rates will ensure we continue to collect for GRI what we were collecting in December 1998.

Sincerely,

Bill Senter

William J Senter
VP Rates & Regulatory Affairs

Attachment

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Original SHEET No. 30D

WESTERN KENTUCKY GAS COMPANY

Gas Research Institute R & D Rider
GRI R & D Unit Charge

Applicable:
This rider applies to the distribution charge applicable to all gas transported by the Company other than Rate T-3 and T-4 Carriage Service. (N)

GRI R&D Unit Charge:
The intent of the Gas Research Institute R&D Unit Charge is to maintain the Company's level of contribution per Mcf as of December 31, 1998. The Unit Charge will be billed according to the transition schedule outlined in the pipelines' tariff.

	Effective Date	Rate Per Mcf
GRI R&D Unit Charge	12/21/1999	$0.0004
	01/01/2000	$0.0007
	01/01/2001	$0.0016
	01/01/2002	$0.0021
	01/01/2003	$0.0025
	01/01/2004	$0.0035

Note 1 The GRI R&D Unit Charge is a weighted average of the rates under the pipelines' transition schedules and applicable annual volumes.

Waiver Provision:
The GRI R&D Unit Charge may be reduced or waived for one or more classifications of service or rate schedules at any time by the Company by filing notice with the Commission. Any such waiver shall not increase the GRI R&D Unit Charge to the remaining classifications of service or rate schedules without Commission approval.

Remittance of Funds:
All funds collected under this rider will be remitted to Gas Research Institute on a monthly basis. The amounts so remitted shall be reported to the Commission annually.

Reports to the Commission:
A statement setting forth the manner in which the funds remitted have been invested in research and development will be filed with the Commission annually.

Termination of this Rider:
Participation in the GRI R&D funding program is voluntary on the part of the Company. This rider may be terminated at any time by the Company by filing a notice of recision with the Commission.

ISSUED: December 21, 1999
(Issued by Authority of an Order of the Public Service Commission in Case No. 99-070 dated December 21, 1999)

EFFECTIVE: December 21, 1999

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

Gary Smith's Pre-filed Testimony in KY on GRI Tariff

KPSC Case No. 99-070

June 1999

Please describe the phased-in restructuring of collecting Gas Research Institute (GRI) Research and Development (R&D) surcharge as proposed by Western

A Consistent with the settlement reached at the Federal Energy Regulatory Commission (FERC), interstate pipelines are phasing-out the billing of GRI R&D surcharge to local distribution companies like Western As a result of this settlement, GRI will lose all of its funding by the year 2004 unless LDCs, in cooperation with their state regulatory commissions, establish alternative funding mechanisms to pick-up the difference Western's proposal is to fully fund GRI in its rates consistent with its December 31, 1998 level of GRI R&D surcharge recovery

Q How will Western phase in its restructured collection of GRI costs?

A Today, the GRI R&D surcharge is recovered through the GCA because it is billed a component of gas cost from the pipeline Since pipelines will no longer include the GRI R&D surcharge per the FERC settlement, we will no longer bill these to the customer as gas costs After discussions with representatives of GRI and the Commission, we have decided to go ahead in this case and directly fund the GRI R&D surcharge as a component of our distribution charge applicable to all gas sold and transported, other than Carriage Services Rate T-3 and Rate T-4 All funds collected under this rider will be remitted to GRI on a monthly basis We will continue to collect the pipeline billed GRI R&D surcharge as gas costs during the transition to full direct funding by Western The restructuring will be complete after 2004

Q When would Western propose to adjust its GRI R&D collections?

A Western would propose to adjust it GRI R&D collections annually consistent with the GRI R&D surcharge level being collected through the pipelines as of December 31, 1998, in conjunction with the transition schedule outlined in the pipelines' tariffs

KEYSPAN

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Joseph F Bodanza
Senior Vice President
Regulatory Affairs and Chief Financial Officer

April 16, 2003

R20 'VE ARE FILED FOR
RECOVERY IN
MASS!

Hand Delivery

Mary L Cottrell, Secretary
Department of Telecommunications and Energy
One South Station, 2nd Floor
Boston, MA 02110

Re Boston Gas Company d/b/a KeySpan Energy Delivery New England, D T E 03-40

Dear Ms Cottrell

Enclosed are an original and nine (9) copies of the Performance-Based Rate Plan of Boston Gas Company d/b/a KeySpan Energy Delivery New England (the "Company") A check in the amount of $355 for filing fees is also enclosed The Company's filing consists of the following

1 Transmittal Letter – Director of Rates,

2 Explanatory Letter – Director of Rates,

3 Notice of Public Hearing,

4 Petition for Approval,

5 M D T E Nos 1209 through 1225, for effect May 1, 2003 under Transmittal Letter from A Leo Silvestrini, Director of Rates and Regulatory Affairs,

6 Testimony and Exhibits of Joseph F Bodanza (Volume I),

7 Testimony and Exhibits of Patrick J McClellan (Volume I),

8 Testimony and Exhibits of Justin C Orlando (Volume II),

9 Testimony and Exhibits of Dr Lawrence R Kaufmann (Volume II),

10 Testimony and Exhibits of Paul R Moul (Volume II),

11 Testimony and Exhibits of Ann E Leary (Volume III),

12 Testimony and Exhibits of A Leo Silvestrini (Volume IV), and

13 Testimony and Exhibits of Ronald B Edelstein (Volume IV)

The Company looks forward to working with the Department and other interested persons during the course of this proceeding All correspondence relating to the filing should be addressed to

Richard A Visconti
General Counsel
KeySpan Energy Delivery New England
52 Second Avenue
Waltham, MA 02451

and

Robert J Keegan, Esq
Keegan, Werlin & Pabian, LLP
21 Custom House Street
Boston, MA 02110

Please acknowledge receipt of this filing on the enclosed copy of this letter and on the copies of the two Letters of Advice and return them to Richard A Visconti in the self-addressed envelope provided

Very truly yours,

Joseph F Bodanza

Enclosures

cc Paul G Afonso, General Counsel
Kevin Brannelly, Director, Rates and Revenue Requirements Division (2 copies)
George Yiankos, Director, Gas Division
Joseph W Rogers, Assistant Attorney General
Robert F Sydney, General Counsel, Division of Energy Resources

<u>Gas Industry Research and Development</u>

Q. Please address the Company's proposal for recovering research and development costs in rates.

A In 1977, the Gas Research Institute ("GRI"), now known as the Gas Technology Institute ("GTI"), was formed by the interstate gas pipeline and LDC industries in agreement with the Federal Energy Regulatory Commission ("FERC") in order to perform research and development ("R&D") for the gas industry To that end, R&D costs were included in a FERC-approved interstate pipeline charge to LDCs, which typically passed the charge on to end-use customers In 1998, FERC, the interstate pipelines and the LDC industry reached agreement to phase out the GTI surcharge of 1 74 cents then being collected in pipeline rates by 2003 In over a dozen states, state regulatory commissions have approved mechanisms to collect an R&D charge through rates to replace the GTI surcharge and maintain funding for these activities In other states, similar programs are under consideration

In this proceeding, Mr Edelstein's testimony addresses the type of R&D initiatives undertaken by GTI for the benefit of gas consumers Based on the historical success of these R&D programs and the resulting benefits to gas customers, Boston Gas is proposing that the Department create an R&D charge that would restore the level of R&D funding previously supported by Boston Gas customers through pipeline-gas purchases in the past Because customers previously funded the R&D based on a surcharge per Mcf of pipeline gas, the

Company proposes to maintain that structure and collect 1 74 cents per Mcf only on pipeline gas and not on liquefied natural gas ("LNG" sales). As a result, the actual charge would be based on the ratio of pipeline gas to total gas purchased by the Company and would actually be less than that 1 74 per Mcf of consumed gas The Company proposes to recover this charge in the Local Distribution Adjustment Charge ("LDAC")

The LDAC charge would begin January 2004, when the current GTI surcharge is scheduled to expire Based on test year weather-normalized load, annual R&D revenues would be approximately $1 4 million

Q. How will the Company supervise the use of the R&D funds?

KeySpan has an internal R&D unit that supervises the expenditures of R&D program funds using the funding generated by the New York LDCs KeySpan uses the funds to support various R&D efforts, including the GTI program, Pipeline Research International, the U S Department of Energy, and Battelle Laboratories KeySpan would use the same approach in applying the funding provided by Boston Gas customers, which is to use the funds in a way that maximizes value for Boston Gas customers on a cost-effective basis

Q. What types of R&D programs does the Company intend on sponsoring?

A The programs will all be of benefit to the Company's sales and distribution customers These consumer-interest R&D projects would address

- Enhanced distribution system integrity, reliability, and deliverability

- Enhanced distribution system security
- Lower distribution system O&M costs
- Enhanced health and safety (distribution system, gas consumer, and general public)
- Enhanced distribution system environmental quality
- Increased-efficiency, lower-emissions end-use equipment

Q. Is the Company proposing specific programs at this time?

A No At this time, the Company is requesting that the Department approve the restoration of the level of funding that was in place in 1998 of 1 74 cents per Mcf and approve using the LDAC for that purpose The Company would then file a program proposal with the Department by December 1 of this year, and by October 1 of each subsequent year The R&D program proposal would outline the Company's annual plan for funding of R&D initiatives within a program budget that is based on anticipated collections The LDAC charge would begin on January 1, 2004, when the current GTI surcharge is scheduled to expire

Q. Does this complete your testimony?

A Yes It does

WITNESS EDELSTEIN
D T E 03-40
EXHIBIT KEDNE/RBE-1

DIRECT TESTIMONY OF RONALD B. EDELSTEIN

GAS TECHNOLOGY INSTITUTE

ON BEHALF OF

BOSTON GAS COMPANY

D/B/A KEYSPAN ENERGY DELIVERY NEW ENGLAND

DIRECT TESTIMONY OF RONALD B. EDELSTEIN

GAS TECHNOLOGY INSTITUTE

EXHIBIT KEDNE/RBE-1

D.T.E. 03-40

Q. Please state your name and business address.

A My name is Ronald Edelstein. My business address is 1700 South Mount Prospect Road, Des Plaines, IL 60018.

Q. By whom and in what capacity are you employed?

A I am employed by the Gas Technology Institute ("GTI") as Director, State Regulatory Programs

Q. Please describe your educational background and professional experience.

A. I graduated from the University of Florida with a BS in Aerospace Engineering (1969), Rensselaer Polytechnic Institute ("RPI") with an MS in Engineering Science: Solid Mechanics (1972), and another MS from RPI in Engineering Science: Environmental Science & Technology (1977). I began my employment with Pratt & Whitney, working as a structural engineer on gas turbines for 8 years. I was then employed by Planning Research Company as an engineering consultant to the U.S Department of Energy doing research and development ("R&D") on solar thermal technologies for three years, then the Solar Energy Research Institute as an R&D planner for three years, then the Gas Research Institute ("GRI"), now GTI, for 20 years, as an R&D planner, strategic planner, Director of Planning, Director of Sales, and currently Director of Regulatory Programs.

Q. Have you ever testified before any state regulatory commission?

A. No, but I have submitted written testimony before the Kansas Corporation Commission in the matter of the 2003 base rate case filing of Kansas Gas Service. Oral testimony in Kansas is expected later this year.

Q. What is the purpose of your testimony?

A The purpose of my testimony is to summarize the results of gas R&D over the last two decades, to describe the cost savings, increased safety, and other benefits that Massachusetts consumers now receive from this R&D, to describe unmet gas consumer R&D needs, and to request that the Massachusetts Department of Telecommunications and Energy ("DTE") authorize Boston Gas Company d/b/a KeySpan Energy Delivery New England ("Boston Gas" or the "Company") to collect a surcharge from its customers to fund gas-consumer-benefits R&D.

Q. What is "gas-consumer-benefits research and development"?

A This is specific R & D in which the applicable technologies result in benefits to gas consumers.

Q. What is the GTI?

A Natural gas local distribution companies ("LDCs") and pipeline companies, in agreement with the Federal Energy Regulatory Commission ("FERC"), formed the GRI in 1977 in the midst of natural gas curtailments and a predicted gas supply shortage. That organization has performed R&D management for over 25 years on behalf of gas consumers and the gas industry that has resulted in over 400 products, processes, and techniques reaching the marketplace. In 1999, GRI merged with the Institute of Gas Technology, the nation's foremost gas R&D laboratory, to form GTI

Q. Is GTI the only organization that manages and performs R&D for gas consumers and the gas industry?

A. No GTI, Northeast Gas Association "formerly NGA/NYSEARCH," the Pipeline Research Committee International, the U S Department of Energy ("DOE"), Battelle Laboratories, Southwest Research Institute, Sandia National Laboratories, universities, manufacturers, R&D firms, and individual LDCs have managed and performed R&D on the behalf of gas consumers and the gas industry over the last two decades

Q. What have been the benefits of these efforts to Boston Gas customers?

A. Substantial benefits have accrued to Boston Gas consumers in the form of lower-cost and more abundant natural gas supply, increased safety and reduced distribution and transmission system costs, reduced demand and lower energy costs from increased-efficiency and lower-emissions end-use equipment

Q. Can you describe in more detail the benefits consumers realized as a result of natural gas supply R&D?

A. Yes The most important result from natural gas supply R&D is the bringing on line of "unconventional gas" from coalbed methane, tight gas sands, and other low-permeability resources. Production of coalbed methane, called "moonbeam gas" by its detractors in the early 1980's, jumped from 100 billion cubic feet ("bcf") /year in the 1980s to over 1,000 bcf /year in the 1990s. During the same period, production of tight sands gas went from only 300 bcf /year to over 2,000 bcf /year. R&D performed by GTI, the U.S. DOE, producers, and others reduced the technical risks inherent in finding and recovering these unconventional gas resources and bringing them into mainstream production This helped to produce the "gas bubble" of the 1980s, which resulted in major increases in natural gas production, helping to bring down the price of natural gas to customers of Boston Gas and across the country.

Q. What have been the results of R&D efforts to increase the safety and reduce the cost of gas transmission and distribution systems?

A. R&D efforts have resulted in new classes of equipment, procedures, and materials becoming available for gas distribution systems, bringing down the cost of installation and helping to reduce operations and maintenance costs

Q. Can you give a specific example of the new classes of equipment?

A. Yes. Most gas mains and services installed in the 1970s used trenching tools, which tore up the surface and subsurface, increasing restoration costs and risked penetrating near-surface utility lines. Six years of R&D yielded the first set of guided horizontal boring tools which are now in general use throughout the gas industry, providing substantial O&M cost savings. This "trenchless" technology saves substantial dollars and has a lot less impact on the surface than the older technologies.

Q. Can you give a specific example of the new procedures that have been put in place?

A Yes. Plastic pipe squeeze-off guidelines, procedures for minimizing static electric discharge on plastic pipe, shoring guidelines, and electrofusion joining guidelines have all provided critical information to LDCs that have enabled them to maintain and increase their already high safety record.

Q. Have there been other R&D-based advances that have improved operational safety?

A. Yes. The newly developed optical methane detector, for example, works by shining a light beam across the front of a vehicle enabling the operator to quickly and reliably scan streets for methane leakage. Many LDCs conduct required leak inspections by a walking survey; the OMD will allow LDCs to convert to driving surveys with a significant reduction in response time and reduction in labor cost.

Q. Can you describe the new materials that have been made available as a result of R&D?

A Yes Major advances in the understanding of polyethylene pipe, or PE, have resulted in superior medium and high-density PE materials, with substantial cost savings over steel mains that were used in the 1970s and 1980s. PE now accounts for over 90% of the new mains going into service For in-home use, R&D has resulted in the development of corrugated stainless steel tubing, or "CSST", that can be "snaked" though the walls, reduces costs directly for the home owner and apartment renter in installing interior gas piping.

Q. What has been the primary emphasis of end-use R&D?

A. The development of increased-efficiency, lower-emissions end-use equipment has been the main target of end-use R&D for residential, commercial, and industrial customers.

Q. What results has gas-consumer-interest R&D had with its research into residential space heating?

A Prior to the early 1980s, a typical home furnace efficiency was in the range of 60% to 70% With the introduction of the 96%+ efficiency fully condensing pulse combustion furnace, we raised the bar and encouraged manufacturers to develop options for the fully condensing furnace Today, condensing furnaces with over 90% efficiency account for about 25% of residential furnace sales; the pulse combustion furnace and its derivatives are still among the most efficient furnaces on the market.

Q. What about commercial applications of GTI's R&D?

A. R&D efforts have produced a new generation of engine-driven, absorption, and desiccant-based cooling systems. First-generation single-effect absorption cooling systems had coefficients of performance ("COPs") of 0.6; the efficiencies of these new systems (developed as a result of GTI and other R&D) are verified for COPs ranging from 0 8 to 1.2, producing gas savings as well as lowering peak electric loads.

Q. What about industrial applications of gas-consumer-interest R&D?

A. Advancements in industrial combustion equipment helped increase the efficiency and lower the emissions from process heating and boiler steam production markets. For instance, in 2001, advanced oscillating combustion on a forging furnace resulted in a 49% decrease in NOx emissions and a 3% decrease in fuel usage, while keeping the average CO emissions below 100 ppm, this technology has applications to a wide range of high-temperature industrial furnaces.

Q. Would the private sector have invested in this R&D without the existence of gas-consumer-interest R&D funding?

A That is not likely, because current laws and regulations in general require far lower efficiencies and allow higher NOx emissions. Manufacturers generally have no incentive – cost or otherwise – to produce such efficient or environmentally friendly equipment. What gas-consumer-interest R&D accomplishes is to lower the technical risk to the point at which manufacturers can then pick up the technology and carry it to the marketplace

Q. How does R&D contribute to consumer safety?

A. Typically, as new equipment is developed, systemic gaps between sectors can cause problems in the areas of safety and reliability. For example, gas furnace corrosion is dependent on vent system design and installation but, typically, the meter and upstream service is handled by the LDC, the furnace by the manufacturer, and the vent system by the installers. As manufacturers began to offer partially condensing furnace designs with 80% to 90% efficiencies, the heat exchanger and vent system began to experience corrosion problems which did not exist in the lower-efficiency furnaces sold before 1981. R&D enabled the design of improved heat exchangers and developed vent installation instructions that minimized the amount of condensation and hence corrosion. Today, these furnace installation instructions are included in every residential furnace sold in the U.S , and its vent design procedures have been incorporated into the National Fuel Gas Code.

Q. Do you have other examples of safety-related R&D?

A Yes Other safety-related research resulted in the elimination of "false positives" from CO monitors and developed scientific data for acceptable NOx levels for indoor air quality. In 1998, a consumer safety R&D project introduced a test methodology to evaluate new water heater designs that could reduce or prevent flammable vapor incidents when flammable liquids are improperly stored adjacent to the heater

Q. What R&D issues and potential benefits remain for gas consumers and the gas industry?

A I believe there are substantial remaining issues for gas supply, delivery, and use that have environmental benefits, safety benefits, and cost savings to customers There are many vital reasons for continuing consumer-interest R&D funding. Some examples of needed R&D that would benefit Boston Gas customers include:

- Substantial research is needed to enhance the confidence in current nondestructive evaluation ("NDE") techniques used to inspect natural gas pipelines and higher-pressure distribution lines. A substantial portion of the national pipeline system is not "piggable"; that is, valves, bends, turns, reduced-diameter pipe sections, or other obstructions prohibit internal inspection by moving a mechanical device, or "pig", through the pipe Further, current NDE tools and technologies can detect pipe wall thinning and circumferential flaws but other types of flaws, such as stress corrosion cracking and axial flaws, are very difficult to detect. Only additional R&D can ameliorate these and other issues such as pipeline coatings lifetime determination and microbiologically influenced corrosion.

- Despite 20 years of research, we are still unable to reliably locate buried plastic pipe under all types of soil and moisture conditions Tracer wire laid above the pipe is helpful but, since it can corrode or break, locating plastic pipe by tracer wire is not always reliable.
- The guided horizontal boring tools described earlier are guidable from point to point as well as steerable, however, they still cannot "see" in front of themselves underground. The ability to locate sewer pipes, utilities and other obstacles is still an important and unresolved safety issue.
- Infrastructure Security is at the forefront of national attention following the events of 9/11. R&D in this area is still uncharted; yet the "cyber" and physical security of our natural gas infrastructure is critical to gas consumers and the national interest
- Environmental issues surrounding old manufactured gas plant sites will cost millions of dollars to clean up. Environmental research, beginning with the determination of environmentally acceptable endpoints ("how clean is clean?"), is still required to minimize environmental compliance costs.
- End-use programs that are under development but which will not be able to proceed without continued funding include a low-cost, fully condensing residential water heater which is over 92% efficient, a residential heating-only absorption-based gas heat pump with a heating COP of 1.4, and an industrial super-boiler with efficiencies over 96% currently being funded by DOE as a laboratory sub-scale pilot project.

- A low-cost residential/commercial fuel cell is still not on the horizon The private sector and DOE are developing a host of technologies for distributed generation, including larger fuel cells, reciprocating engines, and microturbines. However, their successful integration into the gas distribution system and electric grid is still not assured, emissions and costs (compared to central station generation and electric T&D system upgrades) need to be analyzed, and their impact on the reliability of the gas and electric infrastructure has not yet been documented.

Q. How is GTI currently funded?

A Since it was established in 1977, GTI has been funded through a FERC-authorized surcharge on gas transported over the interstate pipelines. Boston Gas customers have supported GTI R&D through upstream supplier prices, which were in turn charged under Boston Gas's retail cost of gas The surcharge was 1.74 cents per Mcf surcharge until 1998. The surcharge has been transitioned down to 0 56 cents per Mcf in 2003 The FERC has decided to discontinue that charge at the end of 2003 and transfer the funding authority to the state jurisdiction

Q. Why was the FERC surcharge phased out?

A This phase out was the result of gas industry restructuring. Increased pipeline-to-pipeline competition and discounting of large customers led to gas pipeline concerns that carrying the R&D surcharge could put the pipeline at a competitive disadvantage relative to those pipelines that did not carry the surcharge. This led to the 1998 FERC Settlement Conference, that, while endorsing the benefits of consumer-interest R&D, phased out the FERC-approved funding mechanism. However, the FERC gave GTI and the gas industry seven years to phase in a state-by-state surcharge and encourage state commissions to proceed on that basis

Q. **Would you summarize your testimony?**

A. Consumer-interest R&D benefits all customers. Over the past twenty-five years, gas consumers have realized billions of dollars of benefits from gas consumer interest R&D. Our overall consumer benefit-to-cost ratio is 9/1, including all R&D costs and benefits from commercialized products and services. Based on our over twenty-year track record of maintaining benefit-cost ratios of over 9/1, I believe that in the future Boston Gas can sustain this benefit-cost ratio for Boston Gas's customers.

These R&D programs are very important for Boston Gas's customers, and I support the Company's proposal even if the Company should choose not to use the services of GTI

Continuation of the gas-consumer-interest R&D program is absolutely critical for the continued distribution and use of natural gas as a current and future environmentally benign, domestically produced energy source for Massachusetts and for the United States.

Q. **Does this conclude your testimony?**

A Yes.

N H Filing

abilities. The Company continues to assess the need for implementation of a step adjustment mechanism to recover these types of non-revenue producing expenses.

Q. **Please describe Northern's proposed treatment of costs associated with gas industry research and development activities.**

A. As the Commission is aware, historically, the gas industry has worked to jointly fund industry-specific research and development ("R&D") initiatives through such organizations as the Gas Research Institute ("GRI"). Over the years, these R&D efforts have led to the introduction of new materials, equipment and techniques to the industry that may otherwise not have occurred, and have benefited Northern and its customers. In the past, Northern's contribution to these initiatives was mandated by the Federal Energy Regulatory Commission ("FERC") through GRI surcharges paid to interstate pipelines and subsequently recovered by Northern through its Cost of Gas Adjustment. In 1999, the FERC modified its GRI cost recovery policy such that by 2003, GRI's sole source of funding will be through voluntary contributions. In the future, it is unclear exactly which entitites will provide this type of R&D, but GRI has proposed a program allowing LDCs and their customers to continue to receive the types of benefits that have been historically received through cooperative R&D efforts

Specifically, GRI is offering each investor the opportunity to direct their research dollars into R&D programs that will address their particular business challenges either through a mutual fund approach, known as the Non-FERC R&D Mutual Fund, or through the GRI Select programs

Because Northern believes in the benefits associated with cooperative R&D, and GRI's costs will not be recovered in the same manner in the future, Northern has proposed an adjustment to test year data to recover R&D expense through its Delivery Service rates. This proforma adjustment for R&D expense of $100,000 reflects a representative level of R&D expense, based on historical activities. Specifically, Northern based this adjustment on the approximate level of GRI funding paid in 1998, the last full year Northern paid GRI surcharges before the change in FERC policy This adjustment is shown as adjustment 8 on Schedule NU-2-2-1, page 2 of 3

Q. **Please identify the other witnesses who are presenting prefiled direct testimony in this docket.**

A. The following witnesses are sponsoring testimony in this proceeding.

- Exhibit NU-2 is the Prefiled Direct Testimony John Skirtich, a regulatory specialist with Acloché LLC Mr Skirtich addresses the Company's proposed revenue requirements, including rate base

Northern Utilities, Inc.
New Hampshire Division
Summary of Adjustments
Reflected in Column 2 of Schedule 2 - Operating Income Statement

Adjustment No.	Adjustment	Amount (1)
7	To record amortization of rate case expense (Schedule NU-2-2-2, Page 3 of 9) A&G Expense	250,000
8	To record research and development costs related to GRI activity (See Exhibit NU-1, testimony of Mr Bryant)	100,000
9	To Adjust interest expense on customer deposits (Schedule NU-2-2-2, Page 4 of 9)	(9,900)
10	To Adjust property taxes (Schedule NU-2-2-3)	30,554
11	To Eliminate unrecoverable amortization (Schedule NU-2-2-2, Page 5 of 9) Amortization	(1,404,000)
12	To Adjust Depreciation expense for proposed rates (Schedule NU-2-2-2, Page 6 of 9) Depreciation expense	241,489
13	To Adjust for injuries and damages (Schedule NU-2-2-2, Page 7 of 9) A&G Expense	39,858
14	To adjust bad debt expense to a 4 year average level (Schedule NU-2-2-2, Page 8 of 9) Customer Accounting Expense	(127,049)
15	To record O&M expenses related to maintenance of MFG sites that have been remediated (Schedule NU-2-2-2 page 9 of 9) Distribution Expense	169,111
16	To adjust Income Taxes based on adjusted taxable income (Schedule NU-2-2-6)	748,710
	Total Revenue Deductions	(6,479,216)
	Net Gas Operating Income Adjustments	1,076,654

DG 01-182 NORTHERN UTILITIES, INC.
Filed: 09/19/01 Notice of Intent to File Rate Schedules

09/19/01 To Meribeth Ladd, Esq. from Thomas B. Getz dated September 19, 2001 please use Docket Number DG 01-182. If your computer capabilities allow, please include along with all formal filings in this docket a floppy disk containing the filed information in format compatible with the NHPUC computer system. We utilize WordPerfect Version 6.1 but can accept other versions of WordPerfect and ASCII You may direct any questions in this regard to our MIS Department. Also any information for which you wish to request confidential treatment, whether as hard copy or on floppy disk, must be filed separately from nonconfidential information. Enclosing a copy of the service list to be utilized for filings in this docket. Please contact the Office of the Commission if you require a copy of our procedural rules (Chapter 200) or, if your computer capabilities allow, you may download it from our electronic bulletin board at 271-2289 or from our Internet Home Page at http\\www state.nh.us\puc\puc.html.

09/24/01 To Thomas B Getz from Michael W Holmes, Esq dated September 24, 2001 OCA hereby notifies the Commission it will be participating in this case on behalf of residential ratepayers.

11/15/01 To Deborah Howland from Maribeth Ladd, Stanley J Sagun dated November 15, 2001 enclosing Northern Utilities, Inc Volume 1 through 5.

11/15/01 To Deborah Howland from Maribeth Ladd, Stanley J. Sagun dated November 15, 2001 enclosing Northern Utilities, Inc. Temporary Rates

11/15/01 To Deborah Howland from Maribeth Ladd, Stanley J Sagun dated November 15, 2001 enclosing Northern Utilities, Inc =s Draft Order of Notice and Draft Proposed Customer Notice

12/07/01 Order No. 23,863 issued **ORDERED, that Northern Utilities, Inc.=s NHPUC No. 10 - Gas Supplemental No. 1 Pages 1 through 23 and NHPUC No. 10 - GAS First Revised Pages 20, 38, 39, 40, 43, 44, 53, 54, 55, 55-a, 55-b, 56, 57, 59, 61, 63, 70, 72, 74, 76, 78, 80, 82, 84, 86, 88, 90, 92, 94, 95, 96, 97, 98, 99, 99-a, Superseding Original Pages 20, 38, 39, 40, 43, 44, 53, 54, 55, 55-a, 55-b, 56, 57, 59, 61, 63, 70, 72, 74, 76, 78, 80, 82, 84, 86,** 88, 90, 92, 94, 95, 96, 97, 98, 99, 99-a, respectively, be and hereby are SUSPENDED pursuant to RSA 378:6, I(a); and it is FURTHER ORDERED, that a Prehearing Conference, pursuant to N.H. Admin. Rules Puc 203.05, be held before the Commission located at 8 Old Suncook Road, Concord, New Hampshire on January 8, 2002, at 10:00 a.m. at which each party and Commission Staff (Staff) will provide a preliminary summary of its positions with regard to the Petition; and it is

FURTHER ORDERED, that, immediately following the Prehearing Conference, Northern, Commission Staff and Intervenors hold a First Technical Session to review the noticed issues; and it is FURTHER ORDERED, that pursuant to N.H. Admin. Rules Puc 203.01, Northern notify all persons desiring to be heard at this hearing by publishing a copy of this Order of Notice no later than December 11, 2001 in the *Foster=s Daily Democrat, Portsmouth Herald* and *Eagle-Tribune*, publication to be documented by affidavit filed with the Commission on or before January 8, 2002; and it is FURTHER ORDERED, that pursuant to N.H. Admin. Rules Puc 203.02, any party seeking to intervene in the proceeding shall submit to the Commission an original and eight copies of a Petition to Intervene with copies sent to Northern and the Office of the Consumer Advocate on or before January 3, 2002, such Petition stating the facts demonstrating how its rights, duties, privileges, immunities or other substantial interests may be affected by the proceeding, as required by N.H. Admin. Rule Puc 203.02 (a)(2); and it is FURTHER ORDERED, that any party objecting to a Petition to Intervene make said Objection on or before January 8, 2002; and it isFURTHER ORDERED, that Staff and Intervenors may file testimony on Northern=s temporary rate request no later than January 29, 2002; and it is FURTHER ORDERED, that a hearing on the request for temporary rates will be held on February 7, 2002 at 10:00 a.m. at the Commission; and it is FURTHER ORDERED, that in addition to the legal notice required above for the Prehearing Conference, Northern shall publish by January 22, 2002, a display advertisement pertaining to the Temporary Rate Hearing, details of which shall be determined in consultation between Northern and the Commission's Executive Director; and it is FURTHER ORDERED, that the Executive Director shall arrange an evening public hearing in Northern=s service territory and publish the date, time and location of the hearing in the display advertisement.

Comment: Type remainder of order here.

12/12/01 To Debra Howland from Alicia D=Oyely dated December 11, 2001 enclosing interested parties to the service list is Stanley J Sagun of NiSource Corporate Services, Inc. and Thomas Birmingham of Bay State Gas Company

12/13/01 Email to PUC from Don Cloutier How do you justify a price increase to the consumer when gas futures have dropped from $9.00 MMBTU January 2001 to $3.00 MMBTU December 2001.

12/17/01 To PUC from Joseph F. O=Shaughnessy, C Alexander Cohen objecting to the rate increase of Nisource and Northern Utilities Company, request for a 3 8 million annual rate increase

12/31/01 Objection to the proposed rate increase by Northern Utilities, Inc. from Joan S. C. Fisher

01/03/02 To Debra A. Howland from Susan B Kullberg dated January 2, 2002 dated January 2, 2002 enclosing affidavit of publication in the Lawrence Eagle Tribune on **December 11, 2001, Foster=s Daily Democrat on December 11, 2001 and the Portsmouth Herald on December 10, 2001.**

01/07/01 To Debra Howland from Carol A MacLennan, Esq dated January 3, 2002 enclosing Petition for Limited Intervention by the Maine Public Utilities Commission.

01/15/02 To Debra Howland from Marcia Thunberg, Esq dated January 15, 2002 a prehearing conference was held on January 8, 2002 and thereafter, Staff, the OCA, and the company discussed a procedural schedule for the remainder of the case The agreed upon dates appear below Staff, on behalf of the parties and Staff, submit this proposed schedule for Commission approval The Portsmouth City Council chambers at the Portsmouth city hall has been reserved as the location for the evening public hearing, 7 PM on January 29, 2002 Northern has coordinated with Staff on the writing of the display ad for the evening public hearing and Staff is aware Northern expects to publish the ad at least a week before the public hearing

1/8/02	Data Requests due from Staff/Intervenors, Set No 1, to Northern
1/15/02	Data Responses due from Northern, DR 1-1 and DR 1-2
1/22/02	Data Responses due from Northern, Set No. 1
1/23/02	Technical session on temporary rates, conference call at 9.30 AM
1/29/02	Evening public hearing on permanent rates

1/29/02	Staff and intervenor testimony due on temporary rates
2/1/02	Data Responses due from Northern, DR 1-3
2/7/02	Hearing on temporary rates
2/7 and 2/8/02	Technical session on permanent rates
2/15/02	Data Requests, Set No 2, to Northern
3/1/02	Data Responses due from Northern
3/15/02	Data Requests, Set No. 3, due from State and Intervenor to Northern
4/5/02	Data Responses due from Northern
5/15/02	Staff and Intervenor testimony due on permanent rates
5/21/02	Settlement Discussion at PUC
5/24/02	Data Requests from Northern to Staff and Intervenors
6/6/02	Data Responses due from Staff and Intervenors
6/11/02	Settlement Discussions at PUC
6/13/02	Rebuttal testimony due from Northern
6/25, 6/26, 6/27	Hearing on permanent rate request

01/23/02 Transcript of hearing held on January 8, 2002

01/23/02 To Debra Howland from Maribeth Ladd dated January 22, 2002 on behalf of Northern Utilities, Inc is not able to comply with the Commission=s December 7, 2001 Order directing northern to publish such notice by January 22, 2002. Northern requests that it instead be permitted to comply with a publication deadline of January 24, 2002.

01/25/02 To Maribeth Ladd, Esq from Debra Howland dated January 25, 2002 the Commission has determined that the requested extension of time will not prejudice the opportunity of interested parties to attend the hearings The request to publish by January 24, 2002 is granted.

01/25/02 Order No 23,904 issued **ORDERED**, that the procedural schedule set forth below is approved and shall govern the remainder of this proceeding.

Data Requests from Staff/Intervenors, Set No. 1, to Northern	January 8, 2002
Data Responses from Northern, DR 1-1 and DR 1-2	January 15, 2002
Data Responses from Northern, Set No. 1	January 22, 2002
Technical session on temporary rates, conference call at 9:30 AM	January 23, 2002
Evening public hearing on permanent rates	January 29, 2002

Staff and intervenor testimony on temporary rates	January 29, 2002
Data Responses due from Northern, DR 1-3	February 1, 2002
Hearing on temporary rates	February 7, 2002
Technical session on permanent rates	February 7, 2002 and February 8, 2002
Data Requests, Set No. 2, to Northern	February 15, 2002
Data Responses due from Northern.	March 1, 2002
Data Requests, Set No. 3 to Northern	March 15, 2002
Data Responses from Northern	April 5, 2002
Staff and Intervenor testimony on permanent rates	May 15, 2002
Settlement Conference	May 21, 2002
Data Requests from Northern to Staff and Intervenors	May 24, 2002
Data Responses from Staff and Intervenors	June 6, 2002
Settlement Conference	June 11, 2002
Rebuttal testimony from Northern	June 13, 2002
Hearing on permanent rate request	June 25, 26 and 27, 2002

01/31/02 To Debra Howland from Maribeth Ladd, Esq. dated January 30, 2002 enclosing Settlement Agreement Regarding Temporary Rates.

02/01/02 To Debra Howland from Maribeth Ladd, Esq. dated January 31, 2002 enclosing the executed signature page of the Settlement Agreement regarding Northern=s proposed implementation of temporary rates submitted on January 30, 2002

02/06/02 To Debra Howland from Susan B Kullberg dated February 6, 2002 submitting affidavits of publication in the **Foster=s Daily Democrat, The Lawrence Eagle Tribune and Portsmouth Herald on January 24, 2002.**

02/13/02 Transcript of the public informational hearing held on January 29, 2002 held at Concord NH at the NHPUC

02/13/02 Order No 23,920 issued **ORDERED, that the settlement agreement proposed by Northern, the OCA, and Commission Staff is APPROVED; and it is FURTHER ORDERED, that the temporary rates for the various customer classes be implemented on a service rendered basis effective February 7, 2002;**

and it is FURTHER ORDERED, that Northern shall submit tariff pages in compliance within 15 days of the date of this order.

The agreed-upon level of temporary rates of $2.3 million will impact customer classes as follows:

Rate or Class of Service	Percentage Increase
Residential Heating	4.9%
Residential Heating - Low-Income	4.9%
Residential Non-Heating	5.1%
Residential Non-Heating Low-Income	5.1%
G/T-40 High Winter Low Annual	4.9%
G/T-50 Low Winter Low Annual	5.0%
G/T-41 High Winter Medium Annual	4.8%
G/T-51 Low Winter Medium Annual	4.9%
G/T-42 High Winter High Annual	5.0%
G/T-52 Low Winter High Annual	5.2%
Total Average Increase	4.9%

02/22/02 Transcript of hearing held on February 7, 2002

02/25/02 To Debra Howland from Joseph A. Ferro dated February 22, 2002 enclosing annotated tariff pages to NHPUC Tariff No. 10

02/26/02 Kindly remove the NH Office of the Attorney General from your Service List since it has no involvement in this particular matter

03/13/02 To Debra A. Howland from Marcia Thunberg, Esq. dated March 13, 2002 Staff is requesting a modification of the Commission-approved procedural schedule in this docket. Originally, data requests were due to go out March 15, 2002, however, due to delays in Northern assembling responses to Data Request Set 2, Northern, Staff, and the OCA agree it would be more fruitful if data requests were postponed Staff submits the following changed dates for Commission approval
Data Requests, Set No. 3, State and Intervenor to Northern.. .. .March 29, 2002
Data Responses, Set No. 3, due from Northern .. .. April 19, 2002
At this time, Staff does not propose modifying the remainder of the procedural schedule. Staff and the parties expect to hold a technical session either on March 18th or 19th in an effort to facilitate the data request process and preserve the remainder of the schedule.

03/19/02 To Debra Howland from Marcia Thunberg, Esq dated march 19, 2002 Staff is requesting the Commission temporarily suspend the procedural schedule in this matter. Staff had sought and received a modification to the procedural schedule last week, however, even with that modification, it is becoming evident the whole schedule needs to be revisited Staff has sought and received concurrence from the Office of the Consumer Advocate, Maine PUC, and Northern. With that, Staff respectfully requests the Commission grant this request to temporarily suspend the procedural schedule with the understanding that Staff and the parties will posthaste submit a revised schedule

03/22/02 To the Parties from Debra Howland dated March 22, 2002 the Commission has determined that the request is reasonable and will not unduly delay the proceeding The procedural schedule is suspended until further notice

04/04/02 To Mr. Ferro from Jeannette McArthur dated April 4, 2002 this letter will serve t confirm your compliance with Commission tariff filing requirements.

04/12/02 To Debra Howland from Thomas R. Birmingham dated April 11, 2002 enclosing Northern Utilities=s Motion for Protective Order along with a copy of Attachment Staff 3-15, Attachment Staff 3-19 and Attachment Staff 3-40.

04/12/02 To Debra Howland from Marcia Thunberg, Esq dated April 12, 2002 Staff and the parties to this docket have developed a procedural schedule to replace the one approved by the Commission in Order No 23,904:

3/28/02	Data Requests, Set No. 3, to Northern
4/16/02	Data Responses from Northern
5/10/02	Data Requests, Set No 4, from Staff and Intervenor to Northern
5/31/02	Data Responses from Northern
6/21/02	Settlement Discussions at PUC
7/12/02	Staff and Intervenor testimony on permanent rates
7/26/02	Data Requests from Northern to Staff and Intervenors
8/9/02	Data Responses from Staff and Intervenors
8/26/02	Settlement Discussions at PUC
9/4/02	Rebuttal testimony from Northern
September 16, 17, and 18	Hearing on permanent rate request

We would appreciate your assistance in presenting this schedule to the Commission for their approval Thank you

04/15/02 To Debra Howland from Marcia Thunberg, Esq. dated April 15, 2002 Staff concurs with Northern Motion for Protective Order and Confidential Treatment

04/18/02 To The Parties from Debra Howland dated April 18, 2002 the Commission has determined that amending the procedural schedule will promote the orderly and efficient conduct of the proceeding The following revised procedural schedule is approved.

3/28/02	Data Requests, Set No 3, to Northern
4/16/02	Data Responses from Northern
5/10/02	Data Requests, Set No. 4, from Staff and Intervenor to Northern
5/31/02	Data Responses from Northern
6/21/02	Settlement Discussions at PUC
7/12/02	Staff and Intervenor testimony on permanent rates
7/26/02	Data Requests from Northern to Staff and Intervenors
8/9/02	Data Responses from Staff and Intervenors
8/26/02	Settlement Discussions at PUC
9/4/02	Rebuttal testimony from Northern
September 16, 17, and 18	Hearing on permanent rate request

04/24/02 To Debra Howland from Thomas R Birmingham dated April 23, 2002 enclosing Northern Utilities=s Motion for Protective Order along with a confidential version of Attachment B to Audit Request 6-5.

05/10/02 Order No. 23,970 issued ORDERED, that Northern=s Motion for Protective Order and Confidential Treatment with respect to customer information is GRANTED; and it is FURTHER ORDERED, that the Motion for Protective Order and Confidential Treatment with respect to employee compensation data not previously disclosed or made public in annual reports or other publications by the Company is GRANTED; and it is FURTHER ORDERED, that Northern=s Motion, to the extent it relates to compensation of officers, board of directors, or other employees identified or made public in annual reports or other public documents is DENIED in part; and it isFURTHER ORDERED, that the protection afforded by this order extends to any additional discovery, testimony, argument or briefing relative to the confidential information; and it is FURTHER ORDERED, that in future filings, Northern shall continue to submit, concurrent with its request for confidential treatment, both redacted and unredacted filings which the Commission shall protect from disclosure during the pendency of its review of the request for confidentiality, pursuant to N.H. Admin. Rules, Puc 204.06; and it is FURTHER ORDERED, that this Order is subject to the ongoing authority of the Commission, on its own Motion or on

Comment: Type remainder of order here

Comment: Type remainder of order here.

Comment: Insert further information here the Motion of Staff or any party or any other member of the public, to reconsider this Order in light of RSA 91-A, should circumstances so warrant.

05/15/02 To Debra Howland from Joseph A. Ferro dated May 14, 2002 submitting revised tariff pages

06/27/02 To Thomas R Birmingham from Marcia A B. Thunberg, Esg. Dated June 27, 2002 attached please find questions generated at the technical session held there in Concordf this past Frday I understand some Staff and members of Northern have already communicated about these questions. My intent in embodying them in writing is to document your questions and have a means for tracking replies. Staff and intervenor testimony is due July 12,, 2002. We would appreciate responses from Northern within a reasonable time so that Staff can utilize the information in preparing the testimony.

07/12/02 To Debra Howland from Marcia A. B. Thunberg, Esq. dated July 12, 2002 enclosing testimonies of Maureen L. Sirois, Amanda O. Noonan, Stephen P Frink and James J. Cunningham.

07/25/02 To Joseph Ferro from Jeannette M McArhtur dated July 25, 2002 Staff has reviewed the filing and confirms compliance with Puc 1603 filing requirements.

07/29/02 To Debra Howland from Marcia A. B. Thunberg, Esq. dated July 29, 2002 enclosing amended testimony of Maureen L. Siroisstaff has corrected those errors an this testimony is being submitted with an attached correction sheet to aid in comparing the older testimony with the amended testimony.

08/01/02 To Debra Howland from Joseph A Ferro dated July 31, 2002 attached for filing Northern Utilities' revised tariff pages to NHPUC Tariff No. 10-Gas, Supplement No. 2

08/15/02 To Joseph A Ferro from Jeannette M. McArhhur dated August 15, 2002 Staff has reviewed your filing and confirms compliance with Puc 16 03 filing requirements

08/21/02 To Debra A. Howland from Marcia A B Thunberg dated August 21, 2002 enclosing Staff, Northern and OCA request the Technical session originally approved for August 26, 2002 be moved to Thursday August 29th 2002 A scheduling problem has caused this change and Staff, Northern and the OCA have agreed to this new date

08/22/02 To the Parties from Debra Howland dated August 22, 2002. Enclosing On August

21, 2002 Staff, Northern Utilities Inc. and the Office Of Consumer Advocate filed a request to move the Technical Session currently scheduled for August 26, 2002, due to scheduling problems An Alternative date of August 29, 2002 was agreed to by the parties

08/22/02 To Debra Howland from Marcia A B. Thunberg Staff Attorney dated August 21, 2002 Enclosing is the amended testimony in the docketed matter. Staff had submitted the testimony of Stephen P. Frink, Assistant Director of the Gas and Water Division back on July 12, 2002 On July 29th 2002 staff submitted amended testimony of Maureen Sirois Ms Sirois's testimony changed as a result of calculation errors discovered and corrected subsequent to that filing.

09/05/02 To Debra Howland from Maribeth Ladd dated Sept. 4th 2002 enclosing Northern and Staff hereby jointly move to revise the previously approved procedural schedule to require the submission of Northern's rebuttal testimony Sept 10th 2002 the Movants contemplate that, thereafter, the procedural schedule would remain as previously approved Thus, the granting of this motion would not delay the ultimate resolution of this case, which includes evidentiary hearing on Sept.16th,17th, and 18th, 2002 The sole purpose of this motion is to facilitate the near-term negotiation of a settlement agreement.

09/09/02 To Maribeth Ladd from Debra Howland dated Sept. 9th 2002 enclosing On Sept. 4th 2002 you filed a letter motion on behalf of Northern Utilities, Inc. and Staff requesting a modification of the procedural schedule proceeding According to your request, Northern, the OCA and Staff have been in settlement discussions and Northern has agreed to postpone the submission of its rebuttal testimony to facilitate negotiations. You also state that OCA concurred with your motion. The Commission has determined that good cause exists for an extension and will not unduly delay the proceeding Accordingly, the request to file Northern's rebuttal testimony by Sept 10, 2002 is approved

09/12/02 To The Parties from Debra Howland the Commission has determined that postponement of the hearings would be in the best interest of all parties at this time The Hearings scheduled for September 16 through September 18, 2002 have been rescheduled to October 2 and October 3, 2002 at 10 a m.

09/12/02 To Debra Howland from Marcia Thunberg, Esq. dated September 13, 2002 the hearings scheduled for September 16 through September 18, 2002 have been rescheduled to October 2 and October 3, 2002 at 10 a m. Staff and the Parties recognize this postponement request does not meet the 7-day notice requirement and request the Commission waive Puc 203 12

DG 01-182

09/26/02 To Debra Howland from Marcia Thunberg, Esq. dated September 26, 2002, enclosing Settlement Agreement entered into between Northern Utilities, Inc, the OCA, and Commission Staff. Volume 1.

09/27/02 Settlement Agreement Permanent Rates Volume 2 through 10

10/04/02 To Debra Howland from Marcia A.B. Thunberg, Esq Srws October 3, 2002 enclosing exhibits to replace copies which were used at the hearing held on October 2, 2002.

10/09/02 Transcript of hearing held on October 2, 2002

10/28/02 Order No. 24,075 issued **ORDERED,** that the Settlement Agreement proposed by **ORDERED,** that the Settlement Agreement proposed by Staff and the Parties is APPROVED; and it is **FURTHER ORDERED,** that the permanent rates for the various customer classes be implemented on a service rendered basis effective November 1, 2002; and it is **FURTHER ORDERED,** that Northern shall submit tariff pages including any approved in compliance within 15 days of the date of this order; and it is **FURTHER ORDERED,** that Northern submit its rate case expenses for Commission review and approval; and it is **FURTHER ORDERED,** that Northern submit its reconciliation report, including a specific proposal for implementing either a surcharge or refund, whichever is necessary, within thirty days from the date of this order Staff and the Parties is APPROVED, and it is**FURTHER ORDERED,** that the permanent rates for the various customer classes be implemented on a service rendered basis effective November 1, 2002; and it is **FURTHER ORDERED,** that Northern shall submit tariff pages including any approved in compliance within 15 days of the date of this order; and it is **FURTHER ORDERED,** that Northern submit its rate case expenses for Commission review and approval; and it is **FURTHER ORDERED,** that Northern submit its reconciliation report, including a specific proposal for implementing either a surcharge or refund, whichever is necessary, within thirty days from the date of this order

Case Closed

11/14/02 To Debra Howland from Joseph A. Ferro enclosing Northern Utilities' compliance tariff pages, as required by NHPUC Order No 24,075 (October 28, 2002)

11/25/02 To Jeannette McArthur from Susan B Kullberg dated November 20, 2002 it has come to our attention that four incorrect pages were filed on November 12, 2002 in compliance with the Commission's Orders in DG 02-167 and DG 01-182. Please replace the incorrect pages previously filed with the attached pages.

12/04/02 To Joseph A. Ferro from Jeannette m. McArthur dated December 4, 2002 Staff has reviewed the filings and confirms compliance with Puc 1603 filing requirements.

NORTHERN UTILITIES, INC.

DG 01-182

EXHIBITS

DATE	NO.	DESCRIPTION	WITNESS
10/01/02	1	September 26, 2002 Settlement Agreement	
10/01/02	2	Attachment A – Petition of Northern Utilities' for Authority to Establish Permanent Rate Increase, filed 11/15/01	
10/02/02	3	Attachment D – Settlement Report of Rate Changes	
10/02/02	4	Schedule E-1 –Settlement Revenue Requirement	
10/02/02	5	Schedule E-2 – Settlement Effective Tax Factor	
10/02/02	6	Schedule E-3 – Settlement Income Statement	
10/02/02	7	Schedule E-4 – Settlement Adjustment to Revenues	
10/02/02	8	Schedule E-5 – Settlement Adjustment to Expense	
10/02/02	9	Schedule E-6 – Settlement Savings from Northern Reorganization	
10/02/02	10	Schedule E-7 – Settlement Payroll Adjustment of 2002 Pay Increase	
10/02/02	11	Schedule E-8 – Settlement Settlement Rate Base	
10/02/02	12	Schedule E-9 – Settlement Cash Working Capital	
10/02/02	13	Schedule E-10 – Settlement Depreciation Study Plant Balance s of 6/20/01	
10/02/02	14	Schedule F-1 – LP and LNG Costs	
10/02/02	15	Schedule F-2 – Bad Debts	
10/02/02	16	Schedule F-3 – Working Capital on Gas Costs	

10/02/02	17	Schedule F-4 – Comparison of Indirect Gas Costs
10/02/02	18	Schedule F-5 – Amount of Indirect Gas Costs To Be Recovered Thorough Cost of Gas
10/02/02	19	Attachment G – Letter of John M. O'Brien 7/31/02
10/02/02	20	Schedule 1-1 – Summary of Settlement Permanent Delivery Services Rates (Schedule NU 9-1)
10/02/02	21	Schedule 1-2 – Summary of Test Year Billing Determinants (Schedule NU 9-4)
10/02/02	22	Schedule 1-3 – Settlement Delivery Service Revenue Requirements/Rate Design/Revenue Proof (Schedule NU 9-5)
10/02/02	23	Schedule 1-4 – Calculation of Settlement Cost of Gas Rates (Schedule NU 9-6)
10/02/02	24	Schedule 1-5 – Calculation of Settlement Delivery Service Customer Charges (Schedule NU 9-7)
10/02/02	25	Schedule 1-6 – Settlement Class Average Bill Impacts (Schedule NU 9-8
10/02/02	26	Schedule 1-7 – Settlement Typical Residential Bill Impacts (Schedule NU 99)
10/02/02	27	Schedule 1-8 – Settlement Typical Commerical and Industrial Bill Impacts (Schedule NU 9-10)
10/02/02	28	Schedule 1-9 – Settlement Bill Impacts by Strata (Schedule NU 9-11)
10/02/02	29	Exhibit NU-1- Prepared Direct Testimony of Stephen H. Bryant
10/02/02	30	Exhibit NU-2 - Prepared Direct Testimony of John E. Skirtich and related Schedules of John E. Shirtich
10/02/02	31	Exhibit NU-3 - Prepared Direct Testimony of Paul R. Noul and related Schedules of Paul R. Moul

10/02/02	32	Exhibit NU-4 - Prepared Direct Testimony of Vincent H. DeVito
10/02/02	33	Exhibit NU-5 - Prepared Direct Testimony of Timothy J. Tokish and related schedules of Timothy J. Tokish
10/02/02	34	Exhibit NU-6 - Prepared Direct Testimony of John M. O'Brien and related schedules of John M. O'Brein
10/02/02	35	Exhibit NU-7 - Prepared Direct Testimony of Earl M. Robinson and Depreciation Study by Earl M. Robinson
10/02/02	36	Exhibit NU-8 - Prepared Direct Testimony of Mark Pl Balmert and Related Schedules of Mark P. Balmert
10/02/02	37	Exhibit NU-9 - Prepared Direct Testimony of Paula A. Strauss and Related Schedules, Tariff Pages and Bill Impacts
10/02/02	38	Exhibit NU-Appendix 1 to Mark P. Balmert Schedules
10/02/02	39	NU's Responses to Staff Data Requests, Set 1
10/02/02	40	NU's Responses to Staff Data Requests, Set 2
10/02/02	41	NU's Responses to Staff Data Requests, Set 3
10/02/02	42	NU's Responses to Staff Data Requests, Set 4
10/02/02	43	NU's Responses to Staff Data Requests, Set 1
10/02/02	44	NU's Responses to Staff Data Requests, Set 2
10/0202	45	NU's Exhibits A & B provided during the March Technical Session
10/02/02	39	NU's Responses to Staff Data Requests, Set 1
10/02/02	46	NU's Responses to Information Requests from the June 21, 2002 Technical Session

10/02/02	47	Prepared Direct Testimony of Amanda Noonan
10/02/02	48	Prepared Direct Testimony of Stephen P; Frank and related Attachments
10/02/02	49	Prepared Direct Testimony of James J. Cunningham, Jr. and related Attachments
10/02/02	50	Amended Testimony of Maureen O. Sirois and related Attachments
10/02/02	51	Amended/Supplemental Testimony of Stephen P. Frank and related Attachments
10/02/02	52	Staff Responses to NU's Data Requests

Contact: Carol Churchill

Northern Utilities Receives Approval for 2% Rate Increase in New Hampshire

Northern Utilities, Inc. received approval from the New Hampshire Public Utilities Commission to increase its revenues by approximately $1.05 million, effective Nov. 1, which translates to about a two percent rate increase for the typical residential heating customer. This increase is necessary, due to an increase in the company's operating expenses.

The rate increase will mean that the typical residential heating customer using 77 therms per month will pay about $1.89 more for natural gas.

The rate increase will be somewhat offset by a temporary rate refund that will also go into effect on Nov. 1 and continue for 12 months. Temporary rates allow the company to increase the revenue it collects while the NH PUC reviews the issues in the rate request. Northern implemented a temporary rate increase of about five percent earlier this year, which was higher than the approved permanent rate increase of about two percent. The refund for a residential heating customer using 77 therms per month will be $0.85.

This rate case represents the first time Northern has filed for a general base rate increase in more than a decade. This increase is necessary at this time because Northern can no longer earn an adequate rate of return in New Hampshire, despite aggressive efforts to increase efficiency and reduce expenses. Base rates recover the costs of delivering natural gas to customers, including the cost of local pipes, meters, other equipment, maintenance and operation of these assets, and customer support functions such as billing and meter reading.

Although unrelated to the rate case, Northern's winter Cost of Gas will go into effect on Nov. 1, 2002. The Cost of Gas for this upcoming winter is higher than it was last winter, and will increase customers' bills by about 5.7%. This is due to an increase in the price Northern is paying for winter gas supplies it purchases on behalf of its customers. These costs are passed along to customers, dollar for dollar without profit.

In total, considering the base rate increase, the base rate refund and the Cost of Gas increase, the typical residential heating customer in New Hampshire will see his/her winter gas bills increase by about eight percent over last year. This is a monthly increase of $4.83 for a typical residential heating customer using 77 therms per month.

Northern remains committed to providing convenient payment options to help customers manage their monthly bills. The company offers residential customers, regardless of their income, the Equalizer Payment Plan and personal payment plans. For income-eligible customers, fuel assistance and the utility-sponsored Neighbor Helping Neighbor Fund provide help through the following Community Action Program locations:

-- County Farm Rd., Dover, phone 749-1334.
-- 7 Junkins Ave., Portsmouth, phone 436-3896.
-- 150 Wakefield St., Rochester, phone 332-3963.
-- 683 Lafayette Rd., Seabrook, phone 427-2520.

Additional information about the company's payment options, products and services are available at www.northernutilities.com.

Northern Utilities, Inc. is a subsidiary of Bay State Gas Company, with local headquarters in Westborough, Mass. Bay State Gas serves more than 300,000 customers in 100 communities in Massachusetts and, through Northern Utilities, New Hampshire and Maine. Both companies are owned by NiSource Inc. (NYSE:NI), an energy holding company with headquarters in Merrillville, Ind. As the second largest natural gas distributor in the U.S., NiSource companies serve a high-growth energy corridor from the Gulf of Mexico to the Midwest to New England. NiSource distribution commpanies serve 3.6 million gas and electric customers primarily in nine states.

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DG 01-182

NORTHERN UTILITIES, INC.

Petition for Rate Change

Order Approving Procedural Schedule

O R D E R N O. 23,904

January 25, 2002

APPEARANCES: Rubin and Rudman, L.L.P., by Maribeth Ladd, Esq. on behalf of Northern Utilities Inc.; Office of Consumer Advocate by Kenneth Traum on behalf of residential ratepayers; and Marcia A. B. Thunberg, Esq. on behalf of the Staff of the New Hampshire Public Utilities Commission.

I. PROCEDURAL HISTORY AND BACKGROUND

Northern Utilities, Inc. (Northern) is a public utility organized and existing under the laws of the State of New Hampshire and primarily engaged in distributing natural gas in the seacoast area of New Hampshire and Maine. On September 19, 2001, Northern filed with the New Hampshire Public Utilities Commission (Commission), a notice of intent to file rate schedules and on November 15, 2001, filed a petition for an increase in permanent rates in the amount of $3,834,344. This represents a 7.4% increase over weather-normalized test year revenues, with a bill impact representing an average increase of 8.2% for customers, to be effective on December 16, 2001 (Petition). Also filed on September 19 was a Petition for Temporary Rates in the amount of $3,631,049 or 7.0% over weather-normalized test year revenues. The Office of Consumer Advocate (OCA), entered an appearance on behalf of residential ratepayers on September 24, 2001.

Northern asserts that the increase in revenues is required because it is not earning a return adequate to cover its cost of capital or a reasonable return on the actual cost of its property used and useful in the public service. Northern contends that its overall rate of return was 4.87% for the test year ending June 30, 2001, which is substantially lower than the currently allowed 10.01% rate of return.

On December 7, 2001, the Commission issued an Order of Notice (No. 23,863) setting a prehearing conference for January 8, 2002. The Order of Notice also directed parties to meet for a technical session following the prehearing and to develop a proposed procedural schedule. The prehearing conference and technical session took place as scheduled. On January 15, 2002, Staff submitted to the Commission the procedural schedule proposed by the parties:

Data Requests from Staff/Intervenors, Set No. 1, to Northern	January 8, 2002
Data Responses from Northern, DR 1-1 and DR 1-2	January 15, 2002
Data Responses from Northern, Set No. 1	January 22, 2002
Technical session on temporary rates,	January 23,

conference call at 9:30 AM	2002
Evening public hearing on permanent rates	January 29, 2002
Staff and intervenor testimony on temporary rates	January 29, 2002
Data Responses due from Northern, DR 1-3	February 1, 2002
Hearing on temporary rates	February 7, 2002
Technical session on permanent rates	February 7, 2002 and February 8, 2002
Data Requests, Set No. 2, to Northern	February 15, 2002
Data Responses due from Northern	March 1, 2002
Data Requests, Set No. 3 to Northern	March 15, 2002
Data Responses from Northern	April 5, 2002
Staff and Intervenor testimony on permanent rates	May 15, 2002
Settlement Conference	May 21, 2002
Data Requests from Northern to Staff and Intervenors	May 24, 2002
Data Responses from Staff and Intervenors	June 6, 2002
Settlement Conference	June 11, 2002
Rebuttal testimony from Northern	June 13, 2002

Hearing on permanent rate request June 25, 26 and 27, 2002

II. POSITIONS OF THE PARTIES AND STAFF

A. Northern Utilities Inc.

At the prehearing conference, Northern Utilities briefly summarized its reasons for seeking a rate increase at this time. Northern stated that existing base rates covering the company's non-fuel-related expenses do not provide sufficient revenue to cover operating expenses and provide a reasonable return on invested capital. It has been ten years since Northern requested approval to implement a general rate increase. The Commission's approval of a step adjustment mechanism to offset the impact of an accelerated Bare Steel Replacement Program that took place during the 1990's has helped postpone the need for a general rate increase. Upon questioning by the Commission, Northern agreed to publish a display ad publicizing the upcoming evening public hearing and temporary rate hearing no later than January 22, 2002.

B. Office of Consumer Advocate

The OCA noted that its preliminary review of the filing indicated Northern was probably entitled to an increase. The OCA expressed its concern that the permanent rate request was probably too high. The OCA noted this was likely due to a high cost of capital figure, proformas going out more than 12 months from the end of the test year, improper matching by proforming expenses but not recognizing the corresponding sales and customer growth, etc. The OCA was particularly concerned that the temporary request approximated the permanent request and thus expressed the same concerns that the proposed temporary rates are excessive.

C. Staff

After its preliminary review of the filing, Staff noted the following areas it intends to pursue with the Company: cost of equity, implementation of an automated meter reading system; funding for the Gas Research Institute; Northern's response to customer service complaints; and adequacy of the number of customer service phone lines.

III. COMMISSION ANALYSIS

Having reviewed the proposed procedural schedule, we find that it is reasonable and will aid in the orderly review of the petitioner's filing. Accordingly, we will approve the procedural schedule for the duration of the proceeding.

Based on the foregoing, it is hereby

ORDERED, that the procedural schedule set forth above is approved and shall govern the remainder of this proceeding.

By order of the Public Utilities Commission of New Hampshire this twenty-fifth day of January, 2002.

Thomas B. Getz Chairman	Susan S. Geiger Commissioner	Nancy Brockway Commissioner

Attested by:

Debra A. Howland
Executive Director and Secretary

DG 01-182

NORTHERN UTILITIES, INC.

Petition for Rate Change

Final Order

O R D E R N O. 24,075

October 28, 2002

APPEARANCES: Rubin and Rudman, L.L.P., by Maribeth Ladd, Esq. for Northern Utilities, Inc.; Office of the Consumer Advocate, by Mr. Kenneth Traum on behalf of residential ratepayers; and Marcia A. B. Thunberg Esq. for the Staff of the New Hampshire Public Utilities Commission.

I. PROCEDURAL HISTORY

Northern Utilities, Inc. (Northern or the Company) serves approximately 25,000 customers in the Seacoast region of New Hampshire and Maine. Its last approved general rate increase occurred in 1991. (*Northern Utilities, Inc.*, 77 NH PUC 366 (1992)).

On September 19, 2001, pursuant to N.H. Admin. Rule Puc 1604.05, Northern filed with the New Hampshire Public Utilities Commission (Commission) a Notice of Intent to file rate schedules. On November 15, 2001, Northern filed its proposed tariff revisions, along with supporting documentation, containing new rates designed to produce an increase in annual revenues of $3,834,344, which consisted of a proposed $203,295 increase in indirect gas costs and a $3,631,050 increase in delivery service revenues. This requested increase represents a 7.4% increase over weather normalized test year revenues, with a bill impact representing an average increase of 8.2% for customers. Northern requested an effective date of December 16, 2001.

On September 24, 2001, the Office of the Consumer Advocate (OCA) filed a Notice of Intent to Participate in this docket on behalf of residential utility consumers pursuant to the powers and duties granted under RSA 363:28,II.

On November 15, 2001, pursuant to RSA 378:27, Northern filed a Petition and supporting documentation requesting authority to implement temporary rates in the amount of $3,631,049 during the pendency of the Commission's investigation of Northern's permanent rate request in DG 01-182. Northern requested that it be permitted to implement temporary rates effective November 16, 2001.

On December 7, 2001, the Commission issued an Order Scheduling Prehearing Conference and Temporary Rate Hearing and Suspending Proposed Tariffs, Order No. 23,863 (Suspension Order). The Order scheduled a Prehearing Conference for January 8, 2002 and a temporary rate hearing for February 7, 2002.

On January 3, 2002, the Maine Public Utilities Commission (MEPUC) submitted a Petition for Limited Intervention.

On January 8, 2002, the Commission held a Prehearing Conference in Docket DG 01-182. Immediately following the January 8, 2002 Prehearing Conference, Northern, the OCA, and the Commission Staff ("Staff") participated in a technical session at which a proposed procedural schedule was agreed upon.

On January 15, 2002, Staff submitted the proposed procedural schedule for review and approval by the Commission. The procedural schedule was approved by the Commission on January 25, 2002 by Order No. 23,904.

On January 30, 2002, Northern submitted a proposed settlement agreement between Northern, the OCA, and Staff. On January 31, 2002, Northern submitted to the Commission the executed signature pages to the settlement.

On February 13, 2002, the Commission approved the imposition of temporary rates pursuant to Order No. 23,920.

On February 25, 2002, Staff recommended the Commission close docket DA 01-226 and that the affiliate contract between Northern and NiSource Corporate Service, Inc. be considered in the rate case docket, DG 01-182.

On April 8, 2002, the Commission transferred consideration of the NiSource Corporate Services, Inc. affiliate agreement, originally docketed as DA 01-226, to the instant docket.

The Staff and Parties conducted extensive discovery and submitted testimony according to the dates set forth in the procedural schedule. On September 26, 2002, Staff and the Parties submitted a Settlement Agreement (Agreement) concerning the permanent rate portion of this docket.

II. SETTLEMENT AGREEMENT

The Agreement presented to the Commission by Staff and the parties is summarized as follows:

A. Permanent Rate Levels

The Parties and Staff agreed to permanent rate increase designed to produce an additional $1.05 million in annual distribution revenues above the normalized test year revenues. The increase will be implemented equally among all customer classes, using the method set forth in Northern's filing dated November 15, 2001. This permanent rate increase represents an average increase of 2.25 percent.

1. Revenue Requirement

The parties and Staff agree that the Company's revenue requirement should be $47,746,999, which is 2.25 percent over test year revenues. More specifically, the Parties and Staff agree that the revenue deficiency in this proceeding shall be calculated using the following components:

Stipulated Rate of Return: 7.85 percent.

Stipulated Adjusted Net Operating Income: $3,998,512, (pro forma test year).

Stipulated Rate Base: The overall rate of return shall be applied to the pro forma test year rate base of $58,900,187.

Stipulated Deficiency Before Taxes: $625,153.

Tax Factor: 59.475 percent.

Change in Revenue Requirement: The stipulated annual increase in operating revenues is $1,051,118. This reflects a net distribution revenue requirement increase of $945,739 plus an increase in indirect gas costs of $105,379.

2. Income Taxes

The Parties and Staff agree to recognize the Company's movement from partial flow through tax accounting to full normalization of books versus temporary tax differences.

3. Depreciation

Northern will complete a new depreciation study within five years from the date of the Commission's Order approving this Settlement. The Parties and Staff agree that the net impact on Northern's depreciation expense associated with adjustments is a reduction to Northern's proposed annual depreciation amortization expense of $149,563.

4. Cost of Capital

Northern's long-term debt has been adjusted to reflect the call premium paid to redeem its 9.70 percent Series Senior notes. Also, the cost of Northern's total long-term debt will decrease from a rate of 6.75 percent to 6.08 percent.

B. Customer Service

Northern will strive to meet specified performance goals for its call center, billing, and meter reading operations:

1) 80 percent of all calls in any given month to the billing, service or credit lines be answered within 30 seconds. The thirty-second call answering period will be measured beginning at the point where an incoming call enters the queue for answering by a call center representative. Calls handled by Northern's interactive voice response ("IVR") system shall be considered to be answered in zero seconds.

2) 90 percent of emergency calls received in any given month be answered within 30 seconds. Measurement of Northern's call answering performance will be determined in the same manner as for measure 1, above.

3) No more than 2 percent of all calls, measured quarterly, to call center, or any other service center with the responsibility for responding to customer calls, shall encounter a busy signal or other busy indication.

4) In any given month, 95 percent of all mutually agreed upon appointments for service shall be met on the day scheduled. Customer initiated postponements shall not be included in this measurement.

Staff and the OCA agree not to object to a decision to exit the service business by Northern if Northern demonstrates that other qualified entities are available to perform similar services within Northern's service territory.

5) 95 percent of complaints referred by the Commission Staff will be resolved to the satisfaction of the Commission Staff within 2 weeks.

6) The Parties and Staff agree to meet at a minimum annually and discuss actual performance and performance goals.

7) Northern shall report monthly, to the Commission's Consumer Affairs Division, on the performance goals listed in items 1 through 5 above, comparing actual performance to the performance goals. Northern shall also report its monthly average speed of answer for its billing, credit and service lines, its monthly number of calls abandoned and its monthly average time to abandon.

8) Northern agrees to make test calls to its IVR on a daily basis to monitor the functionality of the IVR system. Northern agrees to notify the Commission's Consumer Affairs Division of any IVR malfunctions that affect customers. Northern further agrees to implement a new IVR system by November 1, 2003. Northern will work with the Parties and Staff in developing its new IVR system.

9) The Parties and Staff agree that Northern shall be subject to an automatic penalty of $5,000 per month for failing to meet any one of the performance goals listed in 1 through 5 above in any given month. Multiple failures to meet performance goals within any given month shall not constitute multiple fineable violations and Northern's maximum monthly penalty exposure shall be $5,000. Under no circumstances shall Northern's annual maximum penalties for performance with respect to all service quality categories exceed $60,000. The Parties and Staff recognize that Northern cannot accomplish the agreed upon service quality goals immediately and agree to a 3 month transition period during which Northern would report its performance but no penalties would be assessed. The three month transition period will be measured beginning on the first day of the month following issuance of a Commission Order regarding this Settlement Agreement.

Northern may request that the Commission grant a waiver of any of these penalties. If Northern requests such waivers, Northern will bear the burden of demonstrating that its failure to comply with each particular performance target is the result of circumstances beyond its control.

The Parties and Staff agree that Northern may appeal to the Commission the imposition of fines under the terms of this agreement.

C. Step Adjustment to Revenue Requirement and Rates

1. Automated Meter Reading

Northern will install a fully operational automated meter reading (AMR) system by September 1, 2003

2. Recovery of AMR

The Parties and Staff propose a step adjustment to base rates to recover the AMR installation costs, consistent with the requirements of RSA 378:30-a, net of associated annual savings, which the Parties and Staff agree will amount to $162,500.

D. Rate Design

The rate design approved by the Commission in *Northern Utilities, Inc., Revenue Neutral Rate Redesign*, Order No. 23,674 (April 5, 2001), Docket No. DG 00-046, is preserved in this Settlement Agreement.

E. Rate Schedules and Bill Impacts

The Parties and Staff agree that Northern's revised tariff NHPUC No. 10 - Gas should be approved effective November 1, 2002. The agreed-upon level of permanent rates of $1,051,118 result in the bill decrease of 2.25% when compared to previous permanent rates. The agreed-upon level of permanent rates is lower than the current temporary rates by approximately 2.4 to 2.8 percent.

F. Indirect Gas Costs

The Parties and Staff agree that the appropriate level of indirect gas costs to be recovered through the Cost of Gas Adjustment (COG) should be increased to reflect the agreed upon rate of return on liquid propane and liquefied natural gas peaking facilities, and the percentages applied to direct gas costs for bad debt and working capital changed to 0.45% and 0.19%, respectively, to reflect updated costs.

G. Affiliate Agreements

The Parties and Staff request the Commission approve the Agreement entered into between Northern and NiSource Corporate Services, Inc., as filed on November 19, 2001.

H. Effective Date of Permanent Rates

The Parties and Staff propose a November 1, 2002 implementation date for the permanent rates.

I. Reconciliation

The Agreement provides that the revenues collected pursuant to Northern's authorized temporary rates must be reconciled for the period in effect with the permanent rate level approved by the Commission. The difference between the temporary and permanent rates shall be recovered or refunded, without interest.

III. COMMISSION ANALYSIS

New Hampshire RSA 378:7 authorizes the Commission to fix rates pursuant to an order after hearing. The Commission is obligated to investigate the justness and reasonableness of the proposed rates. *Eastman Sewer Company, Inc.*, 138 N.H. 221, 225 (1994). Traditional rate-of-return principles permit a utility to recover prudently incurred operating expenses along with "the opportunity to make a profit on its investment, in an amount equal to its rate base multiplied by a specified rate of return." *Appeal of Conservation Law Foundation*, 127 N.H. 606, 634 (1986).

As part of our review of utility rate matters, it is not uncommon for Staff and the Parties, after extensive discovery, to present a comprehensive settlement agreement and we note that is the case here. We will address the Agreement as the issues were presented therein.

A. Revenue Requirement

Northern's request for permanent rates sought authority to increase annual distribution revenues by $3,834,344, which consisted of a proposed $203,295 increase in indirect gas costs and a $3,631,050 increase in delivery service revenues. Northern's request was based on a cost of common equity of 13.0 percent and an overall rate of return of 9.49 percent. In contrast, Staff submitted the testimony of Mr. Stephen P. Frink and Ms. Maureen L. Sirois who cited annual overearnings in distribution revenues for Northern of $308,641 based on a cost of common equity of 8.89 percent and an overall rate of return of 7.46 percent. (Exh. 48 at 2 line 3) (Exh. 50 at 2 lines 15-16).

In establishing a proposed revenue increase, the Staff and Parties agreed to specific items such as the rate of return, adjusted net operating income, rate base, before-tax deficiency, and tax factor. The Agreement recommends a revenue increase of $1,051,118 and an overall rate of return of 7.85 percent. The rate of return includes a 9.67 percent cost of equity.

At hearing, Northern's witness, Mr. Stephen H. Bryant, explained the difficulties Northern encountered with choosing the 2000-2001 test year. The test year spanned two fiscal years and during one of those years, Northern underwent substantial rate re-design as a result of *Northern Utilities, Inc., Revenue Neutral Rate Redesign*, Order No. 23,674 (April 5, 2001), Docket No. 00-046. (Hearing Transcript of October 2, 2002 (10/2/02 Tr.) at 10 lines 1-3).

A question arose in the context of the rate case concerning Northern's proposed amortization of the net deficient tax reserves and whether this treatment was consistent with normalization requirements in the Internal Revenue Code, as changed by the Tax Reform Act of 1986. In support of the Settlement Agreement, Northern's Assistant Controller assured the Commission that its treatment is correct and resolves any future liability for this tax treatment favorably to Northern's customers. Specifically, in the event the Internal Revenue Service disputes Northern's treatment, Northern agrees not to seek recovery from its customers as the result of any errors in the overall deferred tax deficiency of $1,066,676 that would cause a higher under-collection as of June 30, 2001. Should an over-recovery occur, Northern agrees to refund the amount of the over-recovery to its customers. Staff supported this position and agreed to an adjustment to deferred taxes for calculating Northern's revenue requirement. Northern's offer not to seek recovery is contained in the Agreement. We find this resolution safeguards Northern's customers and we approve the tax issue settlement terms.

In its filing, Northern proposed an approximately $3.0 million depreciation expense. Staff submitted testimony of Mr. James J. Cunningham, which recommended a depreciation expense amount of approximately $2.6 million, a difference of approximately $400,000. (Exh. 49 at 10 line 2-4). In the Agreement, Northern's proposed annual depreciation amortization expense was reduced by $149,563. Staff and the Parties agreed to use of the Broad Group/Whole Life depreciation rates with the applicable plant in service balance as of June 30, 2001 plus the annual amortization of the depreciation reserve imbalance over five years to determine the required level of depreciation expense. These depreciation rates for depreciable plant and equipment are set forth in Exhibit 13, Sch. JJC-3, Page 6 of 7. We find these rates reasonable.

In its filing, Northern proposed approximately $3.2 million for affiliate agreement costs for contracts with NiSource Corporate Service Company and Bay State Gas Service Company. Staff testimony of Mr. James J. Cunningham, entered as Exhibit 49, recommended affiliate agreement costs be limited to approximately $2.3 million. This represented a difference of approximately $900,000 between Northern and Staff's position. In the Agreement, Staff and the Parties settled on an annual affiliate agreement cost that was $426,087 less than Northern's originally proposed $3.2 million.

We recognize that Staff and the parties scrutinized the costs associated with the affiliate contracts in great detail; we therefore accept their recommendation. We will approve the contract between Northern and NiSource Corporate Service, Inc., as adjusted by the terms of the Settlement Agreement.

B. Customer Service

The Agreement contains a significant section devoted to establishing performance benchmarks for Northern. The benchmarks relate to performance at Northern's call center and its performance with billing.

Northern did not submit pre-filed testimony on this issue; however, Northern's witness, Mr. Stephen H. Bryant, did provide some detail at the hearing. Staff submitted the testimony of Ms. Amanda Noonan which was critical of Northern's estimated billing process and its effect on customers. (Exh. 47). Ms. Noonan's testimony indicated Northern's practice of issuing bills every other month coupled with estimated, and sometimes inaccurate bills, caused some customers to not receive an actual, correct bill for many months. (Exh. 47 at 7, lines 14-19). Ms. Noonan also indicated the Commission had received a high level of customer complaints over the past five years, relative to another New Hampshire gas utility and that call center hold times were inordinately high. (Exh. 47 at 2, lines 22-23 and at 3 lines 16-22).

We find that Staff's concerns over billing and call center deficiencies are reasonably addressed by the terms of the Agreement. The Commission has approved similar performance benchmarks with respect to other gas utilities. *EnergyNorth Natural Gas, Inc.*, 85 NH PUC 360 (2000). At hearing, Mr. Bryant stated Northern had the resources to meet the performance benchmarks. He stated he was confident in Northern's ability to install the interactive voice response system, citing the expertise of Northern's parent company. (10/02/02 Tr. at 30 lines 3-9 and lines 17-22). Given the nature of the concerns raised by Staff and Northern's own admission at hearing that it was not providing customers with service levels it should have been, we believe performance benchmarks are appropriate. We are satisfied the benchmarks contained in the Agreement will address Staff's concerns and we approve them.

An element worthy of note regarding the performance benchmarks is that automatic penalties are triggered if Northern fails to meet the benchmarks in any given month. In reviewing Northern's possible exposure to these penalties, we have assessed whether these performance benchmarks strike an appropriate balance. It is not the Commission's intent to impose unachievable customer service levels on Northern, however, the Commission believes customers should receive adequate service levels from the utilities the Commission regulates. The Commission must also consider the impact on Northern's Springfield, Massachusetts call center, which also services customers in Maine and Massachusetts. Any standards imposed by

New Hampshire will also affect customers of Northern's Maine and Massachusetts operations who call that center.

Northern already adheres to similar performance standards in Maine and Massachusetts. At hearing, Mr. Bryant testified as to those performance standards. In Maine, Northern's performance benchmarks are limited and temporary. Massachusetts, however, has more benchmarks and some are similar to those proposed in the Agreement. Mr. Bryant testified the Agreement's performance benchmarks are generally more comprehensive than both Maine and Massachusetts' standards. (10/02/02 Tr. at 24 lines 21-24 and at 25 lines 1-5).

Mr. Bryant also testified that Northern was meeting the Agreement's call answering performance benchmark during the 2000-2001 test year, but that was due to calls getting bumped out of the system. (10/02/02 Tr. at 26-27 lines 22-15). Having said that, Mr. Bryant also went on to explain how he believes the company's call center problems are behind them and he cited examples of expertise Northern's parent company has that will be utilized in achieving the customer service performance benchmarks set forth in the Agreement. (10/02/02 Tr. at 29-30). We feel comfortable that these performance benchmarks provide customers with the level of service they ought to be receiving and are achievable by Northern. Adequate due process protections are also available to Northern should Northern believe a particular automatic penalty is unjust under the circumstances.

C. Step Adjustment for AMR

Step adjustments can be implemented following a rate proceeding, taking advantage of that proceeding to substantially reduce the time for regulatory review and approval of anticipated capital additions. *Pennichuck Water Works, Inc.*, Order No. 23,923 (March 1, 2002), slip op. at 11. The Commission employs step adjustments judiciously as a means of ensuring regulated utilities retain their ability to earn a reasonable rate of return even after implementation of large capital projects. Step adjustments avoid placing a utility in an earnings deficiency immediately after a rate case, which is usually based on a historical test year ratemaking methodology.

In this docket, Northern has agreed to install an Automated Meter Reading (AMR) system. As indicated in the Agreement, the Staff and Parties expect the AMR: will reduce the issuance of bills based on estimated meter readings and will therefore send more accurate price signals to customers; improve meter reading accuracy through the reduction of errors from manual readings; reduce the level of estimated bills rendered due to lack of access to meters; reduce ongoing meter reading costs; and, allow Northern to issue bills based upon monthly readings, in lieu of the current bi-monthly meter reading system. (Exh. 1 at 9). It is believed monthly bills for actual amounts and bills containing fewer errors will foster customer satisfaction. The Commission heard testimony from Northern witness, Stephen H. Bryant, (10/2/02 Tr. at 10 lines 2-21) that the AMR will also reduce meter-reading costs to Northern, amounting to an estimated annual savings of $162,500.

We find the step adjustment and method for recovery proposed in the Agreement are narrowly crafted and that the AMR installation will benefit Northern's customers. For these reasons, we approve the step adjustment.

D. Rate Design and Customer Bill Impact

By Order No. 23, 674, (April 5, 2001) in Docket No. 00-046, the Commission approved a significant rate redesign for Northern. The Agreement preserves that rate design. We see no reason to disturb the rate design at this time and will therefore approve it.

At hearing, Mr. Bryant discussed Northern's Report of Proposed Rate Change, entered as Exhibit 3, which demonstrated that the proposed rate increase will raise each customer class's rate by 2.25 percent. Mr. Bryant explained it was Northern's intent to spread the rate impact as evenly as possible among all rate classes, all seasons, and for all months. (10/02/02 Tr. at 42 lines 14-21). The average rate impact for each class is identified as 2.25 percent; however within each class, some customers may see higher and lower percent impacts. (10/02/02 Tr. at 30-40). Exhibits 25, 26, and 27 verify Northern's efforts and show the variation in percent impact per month and class. According to Exhibit 25, Northern's largest customer class is residential heating, which consists of 17,222 customers out of Northern's 23,738 total customer count. Exhibit 26 demonstrates that during different months of the year, residential heating customers may see a rate increase between 2.05 and 2.83 percent as a result of the Agreement. In comparison, Northern's Petition For Authority to Establish Permanent Rate Increase contained a request for a 7.4 percent increase. (Exh. 2).

In light of the foregoing, we find the Agreement results in rates that are just and reasonable for all customer classes.

E. Effective Date

Each year, Northern adjusts its rates on November 1st to reflect expenses associated with the winter period cost of gas. Because customers are accustomed to rate changes at that time, we find it will result in less customer confusion to allow the new permanent rate to go into effect then. For this reason, we approve implementation of the permanent rate effective November 1, 2002, on a service rendered basis.

F. Reconciliation and Rate Case Expenses

The Settlement Agreement states that the difference in revenues recovered at the temporary rate level and what would have been recovered had permanent rate been in effect during the same period are to be recovered or refunded, without interest, through the Local Distribution Adjustment Clause (LDAC) in effect November 1, 2002 through April 30, 2003. Northern is to file an accounting of the rate case expenses, and those approved by the Commission are to be recovered through the November 1, 2002 through October 31, 2002 LDAC.

In Northern's 2002/2003 Winter COG filing, Docket No. DG 02-167, Northern estimated that the over recovery resulting from a reconciliation of temporary and permanent rates to be $980,000 and rate case expenses for recovery to be $480,000, resulting in net credit of $500,000. Although a final reconciliation and accounting of rate case expenses have not been submitted to the Commission, the LDAC is reconciled as part of the Winter COG filing and any later adjustments would addressed in the reconciliation. At the COG hearing, Northern testified that the estimated costs were very close to being finalized and that the estimates should be close to what is ultimately filed.

We direct Northern to file with the Commission an accounting of the amount of the rate case expenses as well as an accounting of the difference between permanent and temporary rates, for Commission review and approval. The approved reconciliation and rate case expenses will be recovered through the LDAC and reconciled as part of Northern's next winter's COG proceeding.

IV. CONCLUSION

We have reviewed the terms of the Settlement Agreement, as well as Staff and the Party's filings, supporting testimony, and exhibits as presented at the October 2, 2002 hearing. Based on our review of the record, we find the terms, as set forth in the Settlement Agreement will produce rates and service that are just, reasonable and in the public good.

Based on the foregoing, it is hereby

ORDERED, that the Settlement Agreement proposed by Staff and the Parties is APPROVED; and it is

FURTHER ORDERED, that the permanent rates for the various customer classes be implemented on a service rendered basis effective November 1, 2002; and it is

FURTHER ORDERED, that Northern shall submit tariff pages including any approved in compliance within 15 days of the date of this order; and it is

FURTHER ORDERED, that Northern submit its rate case expenses for Commission review and approval; and it is

FURTHER ORDERED, that Northern submit its reconciliation report, including a specific proposal for implementing either a surcharge or refund, whichever is necessary, within thirty days from the date of this order.

By order of the Public Utilities Commission of New Hampshire this twenty-eighth day of October, 2002.

Thomas B. Getz Chairman	Susan S. Geiger Commissioner	Nancy Brockway Commissioner

Attested by:

Debra A. Howland
Executive Director & Secretary

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
DIRECT TESTIMONY
PETER A. CISTARO
VICE PRESIDENT – DISTRIBUTION

My name is Peter A. Cistaro. I am the Vice President – Distribution, Public Service Electric and Gas Company (PSE&G, the Company, Petitioner). In this case, I am serving as the Company's operations policy witness. Schedule PAC-1 describes my qualifications as a witness in these proceedings.

Since our last gas base rate decision we have continued to provide exceptionally reliable and high quality gas service to our customers. Our number one priority as a business is continuing and constantly improving our record of safe gas delivery, but we are challenged by (1) an aging infrastructure that requires modernization, (2) the labor intensive nature of our business, (3) the need to meet increased regulatory requirements, and (4) the expectation of our customers for transactions that can only be enabled by faster information management systems. These necessary expenditures to serve our customers render the Company's current gas base rates inadequate. Our guardianship of the safety and reliability of the gas distribution infrastructure is essential not only to individual customers, be they homeowners or businesses, but to the health and well-being of New Jersey's economy and its valuable image as a desirable place to live and work.

OVERVIEW

In this proceeding, the Company is requesting an increase in its gas base rate revenues sufficient to assure the continued safe and effective operation of our gas distribution system. To support this request, the Company is presenting the direct testimony of three other Company employees in addition to my testimony, and the direct testimony of two outside witnesses. Robert C. Krueger, Jr. is the Company's accounting witness, who will explain the books and records of our Company, and present the test year ending June 30, 2001 in his testimony. Albert N. Stellwag is the Company's financial policy witness and will present pro forma adjustments to the test year and the development of revenue requirements. Mr. Stellwag, in conjunction with outside witness Roger Morin, PhD., will discuss the Company's capital structure and return on equity. Robert L. Hahne, a Partner with Deloitte & Touche, is responsible for the cash – working capital study. Gerald W. Schirra is responsible for the gas cost-of-service study and rate design. My testimony discusses the Company's gas construction program, operations, safety record, reliability and customer satisfaction initiatives.

In a parallel proceeding, new depreciation rates for gas plant are supported by a depreciation study presented by Donald Roff, Deloitte & Touche. The Company requests that the Board consolidate its decision on new depreciation rates with its decision in this proceeding. Accordingly, the impact of the requested depreciation rates has been reflected by Mr. Stellwag in his calculation of revenue requirements.

GAS BUSINESS OPERATIONS

The overriding focus of PSE&G's gas operations is the continued safe, adequate and reliable delivery of gas service through our distribution pipeline system. The importance of maintaining the Company's ability to construct, operate and maintain this essential infrastructure with a focus on safety for both employees and customers cannot be over-emphasized. The Company's gas service territory covers approximately 2,350 square miles, and includes 264 New Jersey municipalities. This is an area of the State in which approximately 61%, or 5 million, of the State's residents live. In order to meet the needs of our customers within this sizeable area, the Company's gas business operates and maintains over 16,000 miles of gas mains of various sizes from 2" to 42," over one million service lines, line valves, pressure regulators, meters, and associated instrumentation and corrosion protection systems. In addition, gas distribution operations also encompasses 37 metering and regulating stations, three Liquid Propane Air (LPA) peak shaving plants, one permanent and one seasonal Liquefied Natural Gas (LNG) peak shaving facilities, and 73 miles of intrastate transmission lines.

The men and women who physically construct, maintain and operate our distribution system and service our customers' requirements, are based out of twelve field headquarters throughout the State, strategically located to provide rapid response to emergencies 24 hours a day, every day. These employees have primary responsibility for hands-on distribution and service activities. Schedule PAC-2 provides a map of our gas service territory with identification of these major gas district operations centers. Personnel at these locations perform construction, maintenance and repair activities, such as main and service installations, leak detection and repair, system design and maintenance, meter and after-meter safety services, and administrative activities associated with this work. The balance of personnel in gas operations is located at the General Office in Newark, at the peak shaving plants in Camden, Burlington, Edison, and Harrison, and at the Measurement Department in Springfield. Other than the Gas System Operations Center, which has direct operating responsibility for the gas system, most of the gas delivery operations associates in the General Office in Newark provide management and technical support to field operations.

Our Customer Operations consist of two inquiry centers and sixteen business offices that in part support Gas Operations by handling customer inquiries and transactions. These are also located throughout our service territory to better respond to the needs of our customers and the communities we serve. Schedule PAC-3 lists the location of these business offices as well as our other Customer Operations locations. Our inquiry centers handle any kind of customer call, from reporting of leaks to billing inquiries, 24 hours a day, seven days a week. The local Customer Service Centers provide essential services that help to safely and effectively serve the gas related needs of our customers as well as providing access to community outreach activities such as

Lifeline, NJ Shares and other assistance programs. Customer Operations are supported by a centralized Billing and Payment Processing Center located in South Plainfield.

CONSTRUCTION PROGRAM

The Company has added over $1.2 billion in construction investment in the gas business since 1993. Through year end 2000, over $500 million was required to provide new mains and services to meet the needs of an expanding population and to support New Jersey's economic growth, and $525 million was needed for replacement and upgrade of mains and services to maintain the safety and reliability of the gas system. All of our constructed facilities are designed to deliver natural gas in sufficient volumes on the coldest day at the least cost to our customers that is consistent with safety and reliability goals. Plant, metering and regulating, and support facilities and projects comprised the remaining $222 million in capital additions. Schedule PAC-4, Gas Business Capital Additions-Actual and Forecast, provides the details of these capital expenditures by year from 1993 through 2000, and by major category: (1) New Business and Load Growth, (2) Replacement and Upgrade of Distribution Facilities, (3) Peak Shaving Plants/Meter and Regulating (M&R) Facilities, and (4) Support Facilities and Projects. Test year expenditures are consistent with historical spending patterns and these levels of spending continue and are necessary in order to assure a safe and reliable gas distribution system. The Company's projection of construction expenditures for the test year and years 2001 and 2002 is also shown on Schedule PAC-4.

1. **New Business and Load Growth Facilities**

New business and load growth facilities are defined as the installation of new mains, services, regulators, and meters required to meet peak hourly gas flows at design conditions for new or incremental loads. Since the beginning of 1993, over 100,000 new customers were added to the system. In the combined last two years alone, over 20,000 new installations were made.

During 2000, $57.6 million was spent on new business and load growth, but we estimate load growth related construction for the test year to be slightly more, $60.4 million, due to over $6 million for two large gas transmission projects for cogeneration customers in 2001. From 1993 through 1996 there was a spurt of growth for cogeneration and third-party generation customers, and we expended over $9.2 million for supply mains for these special customers during that period, but until these two planned projects for 2001, there had been little activity in recent years.

We make every effort to make sure that we are designing our new facilities correctly, and not over- or under- sizing our new mains. The physical facility requirements of new customer loads coming onto the system are determined with the aid of a computer model, the Stoner System, which is an interactive database model of existing and proposed distribution mains. This modeling tool is also used to analyze and determine which segments need system reinforcement for pressure reasons due to general load growth from existing customers. Schedule PAC-5 summarizes the footage of new main installed by year for 1993-2000.

2. **Replacement and Upgrade of Facilities**

Our construction program to replace and upgrade the Company's aging mains and services is an essential part of maintaining the safety of our distribution system and to upgrade the system's design capability. In the year 2000, $84.2 million was spent on replacement and upgrade of facilities, and similar investment is required for the test year and beyond, as noted in Schedule PAC-4. This ongoing rehabilitation is required to maintain the integrity of a distribution system, which is over 65% steel and cast iron. In addition, much of the older main is located in urban centers or under highways, making rehabilitative construction more difficult and expensive than we typically encounter with new mains and services.

The need for replacement of mains and services is based on vigilant monitoring and analysis of break and leak history to evaluate which specific segments of the system need to be replaced to minimize risks from future breakage and gas leaks. In addition, our cast iron removal program targets set amounts of footage of elevated pressure main because of the risk factors presented by this type of main if it breaks. Replacement needs for steel mains and services are also evaluated continually through ongoing corrosion testing and monitoring programs. During 2000, the Company replaced approximately 400,000 feet of main. Schedule PAC-5 identifies the feet of replaced main by year 1993-2000, as well as the amount of new main installed for load growth.

The Company's replacement initiative for steel services focuses on the use of plastic insertion to replace approximately 4,000 to 6,000 bare steel services per year as a result of leaks, the main replacement program and preventive maintenance programs.

Capital is also expended to rehabilitate cast iron bell joints as part of an improved repair process. We employ several new technologies to seal cast iron joints, and in 2000, we sealed approximately 6,000 cast iron bell joints with advanced encapsulation methods. These are described in more detail in the Cost Control section of my testimony.

3. <u>Peak Shaving Plants / Meter and Regulator Facilities</u>

From 1993 through 1995, the Company upgraded the piping and storage at our peak shaving facilities and expanded several metering and regulating stations. As a result of these improvements, our peak shaving plants are better prepared to supply supplemental gas into our distribution system on the coldest days on very short notice. Investments in the Gas Systems Operations Center (GSOC) and the M&R facilities for improved system controls and dispatching will continue as communication and control technologies are constantly evolving with advanced capabilities and enhanced reliability. These upgrades are necessary to assure safe and accurate gas control in our system as well as the continued reliability of peaking supplies during extreme cold weather conditions.

4. **Support Facilities and Projects**

Capital expenditures for support facilities and projects were $20.3 million for the year 2000 and are expected to be $22.7 million in the test year, as shown on Schedule PAC-4. Included in this category are the costs of information systems, vehicles, radios, communication equipment, building improvements, expenditures for office equipment/furniture and various tools and equipment. Information technology and automation of systems that support the business process have moved the Company from paper back office records to integrated work management, and the investment in these backbone business support systems has been essential for the continued satisfactory operation of our distribution system and emergency response infrastructure. System improvements have also been required in Customer Operations to support the changing industry structure as a result of unbundling.

The Support Facility category also includes building renovations. Some of our buildings are over 75 years old, and many others that were built over the last 50 years needed improvements to adapt to modern use and regulatory and code requirements. A safe work environment for employees is essential to the Company, and improvements to buildings, vehicles and reliable communications are important in maintaining a safe workforce that in turn provides safe delivery of our product to our customers.

OPERATIONS AND MAINTENANCE

PSE&G has extensive gas operations and maintenance activities, including finding and repairing gas leaks on mains, services and customer premises, responding to emergency leak situations, responding to gas pressure problems, maintaining, monitoring and controlling gas pressures on the system, maintaining customer accounts, billing, metering, and appliance safety for all customers. Most of our field operation activities are mandated by the U.S. Department of Transportation, including some recent additions to our operations activities, such as new leak surveys, operator qualification training and the installation of automated valves on transmission lines. Other activities, such as research and development participation, training and continuing education, accounting, employee benefit management, information technology, standards development, and participation in industry operations forums are in direct support of an efficient and effective operation.

The Company expended $320 million in the test year, in gas operating expenses net of fuel costs, depreciation, amortization and taxes, as detailed in Schedule PAC-6. In all aspects of operations and maintenance, we strive for excellence in safety, for both our customers and our employees, and excellence in cost control and productivity. We continually measure our level of effectiveness in these areas through reporting, benchmarking and process improvements.

SAFETY

Safety in PSE&G business practices, safety of our customers, and a continuous effort to make safety improvements to our distribution system, are a focus of all who work in our gas business. Because safety is our over-riding business objective, it has also become our daily working philosophy: employee safety leads to system safety, which leads to customer safety. Our employee involvement, particularly the participation of our union representatives, has been a key to the development of our safety practices and procedures. The implementation of peer-to-peer evaluation of work practices, the completion of job hazard analyses for all operations, and completion of root cause analysis training with both union and non-union personnel in a collaborative training effort involving Rutgers University resulted from this overall team effort.

The year 1998 saw the addition of a multifaceted Health and Safety System that focuses on safety at the worker level with the creation of local Councils in every area of the Company. These local Health and Safety Councils address safety concerns of employees, identify safety issues that are raised locally and share solutions and problems with other Councils. We record and distribute our safety results throughout the organization on a monthly basis, with targets for improvement.

Our safety efforts have resulted in dramatic improvements in OSHA recordable accidents over the last seven years in all of Gas Operations. A peer panel comparison to other gas utilities shows that PSE&G has a much better OSHA rating than the average of 30 other utilities. These favorable improvements can be seen in Schedule PAC-7.

We employ the same safety-first mindset with our customers as we do with our employees. Gas service technicians responded to over 131,000 emergency leak calls in the year 2000, with a 99.7% response rate within 60 minutes, and all identified leaks were made safe for our customers. In addition, our technicians responded to over 281,000 heating-related calls in the year 2000. We continue to offer safety checks of gas appliances for proper installation and ventilation, and have actively promoted customer awareness of the dangers and causes of carbon monoxide poisoning. We have equipped our service technicians with special tools and training for checking households for sources of carbon monoxide in response to the growing need to address this safety concern. Over 8,000 investigations for carbon monoxide emissions on customer premises were made in 2000, 45% of which were found to have carbon monoxide present, and were made safe.

CONTROLLING COSTS

The Company's expenditures that I have provided in my testimony reflect the impact of proven cost saving construction methods, such as plastic pipe insertion and joint trenching, as well as the introduction of new technology into our operations. For example, where appropriate, the insertion of polyethylene (PE) pipe into an existing main rather than opening a trench to replace a main results in lower costs because there is less pavement disturbance and restoration required. By reducing the need to excavate, plastic pipe insertion can sometimes result in labor savings of about 50% for larger diameter piping. Another initiative that minimizes construction costs are joint trenching efforts where multiple utility facilities are installed in the same trench, resulting in savings of as much as 70% in new residential developments where this technique can be used.

The Company has actively sought technological innovations which would result in cost minimization while improving quality and safety. We have actively supported the Gas Technology Institute (GTI) (formerly known as the Gas Research Institute, or GRI) with respect to the development, evaluation, and implementation of new technologies. We are proud to be industry leaders in deploying new technologies, and are using the following innovations:

a. Optical Methane Detectors that are significantly improving main leak survey productivity, up to 30%, while enhancing safety for both PSE&G employees as well as the public.

b. Ultrasonic technology to evaluate plastic pipe joint integrity, replacing the laborious task of performing destructive mechanical testing while increasing the quality assurance of our work.

c. Trenchless technologies for the installation of gas facilities has reduced restoration costs and minimized customer inconvenience while increasing productivity. The Guided Piercing Tool extends the usable range of conventional piercing tools by up to 400% by giving the tool steering capability. The use of this tool can save as much as $7 per foot on an average service. Directional drilling technology has been developed to the point where it is now the preferred method of installation for environmentally sensitive locations.

d. Non-metallic leak repair clamps utilizing anaerobic encapsulants repair cast iron joints with material that is not subject to corrosion, and which is much less susceptible to deterioration due to age and vibrations.

e. Vacuum evacuation technology greatly minimizes restoration requirements when used to perform work in smaller pavement holes, commonly referred to as keyholes. Procedures involving the use of the keyhole method include cast iron joint repair using anaerobic materials, service cutoffs, test holes, and anode installations.

f. Closed circuit television inspection equipment used in live gas mains to find the location of elusive gas leaks or points of water infiltration has helped to minimize the time to find difficult leaks, eliminate service interruption time, and reduce customer inconvenience. To date, we have used this technology to inspect over 15,000 feet of main.

g. Three inch and larger coiled polyethylene pipe can be used from rolls that are 365 feet long, as compared to conventional pipe which is supplied in 40-foot lengths. By using coiled pipe, eight out of nine joints are eliminated, resulting in significant productivity gains.

The Company has been very attuned to global developments in improving distribution work methods, and our participation in foreign technology transfer has led to the use of liners, a trenchless technique for renewing pipe which can substantially reduce costs in specific applications while meeting safety and integrity criteria for the gas distribution system. We have installed over 10,500 feet of liners in critical locations where conventional replacement techniques for renewing mains would have been extremely costly and difficult in terms of neighborhood and traffic disruption. Compared to open trenching, using liners has saved the Company over $3 million. A pilot program to use liners in service lines with difficult configurations, is showing a savings of up to $15 per foot from the reduction in the number of excavations required.

We have also put new information technology systems in place to improve customer satisfaction, operations effectiveness and efficiency:

a. The new Gas Management and Control System (GMACS) provides data links to pipeline companies for more accurate billing. The system balances usage versus delivered volumes and automates system recoveries. These features were needed in response to the unbundling of the gas pipeline supply services in order to manage a very complicated system.

b. The installation of the Integrated Work Management System (IWMS), and the Gas Service Information Management System (GSIMS) allows for more accurate work scheduling, planning and data tracking. These enhanced features help to reduce cycle time and help to manage workload and gain more efficient use of PSE&G's resources. Also, increases in productive time, and reductions in time administrators and drafters have been realized.

c. Automation in several aspect of Customer Operations, including: replacement of the meter reading system; implementation of a meter data repository to handle energy usage information; introduction of advanced call center technology including collection voice response unit and intelligent workstations for Customer Service personnel; unbundling the gas bill for customer choice; and finally, developing new mail extraction and remittance systems in order to better process customer payments.

LABOR RELATIONS

The Company has a very strong relationship with represented employees, marked by a common drive for a safe, trained and customer-focused workforce. This shared determination to succeed is exemplified by an historic six-year collective bargaining agreement reached in 1996 and by recent agreements to enter into three-year contract extensions between the Company and the IBEW Local 94 and the UA Local 855. The Company's use of mid-term agreements and mutual gains have provided a road map to help the Unions compete effectively with contractor labor, thus assuring that our customers are getting the best value while preserving jobs for employees that want to work effectively for our customers.

BENCHMARKING AND PROCESS IMPROVEMENT

The Company's gas business participates in the American Gas Association (AGA) Best Practices Benchmarking Project, an annual industry-wide study that focuses on key operating processes and identification of innovative and cost efficient practices among gas distribution companies. PSE&G has been selected by the AGA as a Best Practice company for four consecutive years (1996-99), and is expecting to get favorable ratings when the year 2000 results are released. The information and data that is obtained from this project is incorporated in process improvement efforts at PSE&G. Our Process Improvement (PI) Group is responsible for coordinating process improvement efforts by identifying and measuring performance gaps in our processes and then driving implementation of best practices throughout the organization. As an example, by implementing several processes used at other companies to improve supplier relations, the Company has been able to reduce the number of vendors, thereby allowing better negotiations for goods and services. The PI Group has been successful in identifying many opportunities for cost reductions over the past several years and the combined effort of the PI Group, field operations personnel and senior leadership has resulted in PSE&G being recognized as one of the country's leading companies in the implementation of AGA Best Practices.

The Company has demonstrated its seriousness about performance improvement to its employees by tying a significant portion of their individual compensation to not only their individual performance, but to the performance improvement of the Company's operations. Each year the success of each operating group is measured against target goals and incentive pay is adjusted accordingly. This has been a very effective way to drive change, customer focus and efficiency throughout the organization.

CUSTOMER SATISFACTION

Customer satisfaction is one of the most important internal benchmarks we measure in order to determine how successful we are in serving and focusing on our customers' needs and expectations. In 2000, there were more than a thousand fewer Board and executive inquiries than in 1999, due in part to collection representatives working one-on-one with each customer, flexibility with customers' payment arrangements, fewer storm related inquiries and fewer inquiries concerning service delays and scheduling from gas service operations. Bill inquiries related to the high commodity cost of gas and the increased cold weather have risen in 2001, but our customer surveys show a strong measure of customer satisfaction with the Company overall.

The Company continually surveys our customers to determine their satisfaction with our overall service, and we also perform "Moment of Truth" surveys immediately after providing particular service to customers to measure how well individuals and departments are performing in relation to satisfying our customers. The results are published quarterly for all employees to see, and individuals as well as departments use the results as a tool to improve their performance. The four major areas of measurement for service are telephone service, field service, emergency service, and office service. Our surveys show that residential customers tend to be more satisfied with PSE&G than commercial and industrial customers, but overall, PSE&G measures very favorably against the American Customer Satisfaction Index (ACSI), a well accepted national standard for customer satisfaction. In fact, since the ACSI was started in 1994, PSE&G has outperformed the ACSI Utility Index in every year, except 1999.

RESEARCH AND DEVELOPMENT (R&D) RECOVERIES

PSE&G indirectly provides approximately $2.5 million annually to GTI for research and development through a Federal Energy Regulatory Commission (FERC) funding surcharge on pipeline suppliers that is bundled into our customers' commodity costs as part of the Levelized Gas Adjustment Clause (LGAC). FERC is eliminating this funding mechanism for GTI over a seven-year period, whereby the 1998 FERC surcharge rate of 1.74¢/Dth would be reduced from year-to-year until the surcharge would no longer be in effect by the year-end 2004. Our request is to continue funding research with GTI and other research organizations on a direct basis through base rates.

During the seven-year transition period, as the FERC surcharge is being phased out, GTI has introduced research, development and commercialization program options outside of the FERC funding mechanism to make up for the difference in funding so that ongoing and planned projects can continue. Under the new program, members can select specific research areas to fund that may be of more value to their specific company. Of the total that PSE&G customers contributed under the old plan, GTI directed 52.6% to gas distribution research, 13.1% to transmission pipeline research, and 34.3% to gas production research. To continue the R&D work that is most valuable to PSE&G, we are requesting research funds equal to the portion of 1998 FERC surcharge that funded gas distribution research and the transmission pipeline research, or $1.6 million, through base rates.

As in every industry, R&D efforts are critical if the industry is to keep up with technological advances. The focus of PSE&G's internal gas R&D Program has been the transfer of new technologies from GTI into our operations. As I discussed previously in my testimony with respect to controlling costs and improving safety, GTI funded technologies have provided significant benefits to our operations and our customers. Flexibility in directing R&D funding will enable the Company to continue research in areas that are the most important to us and to our customers. By funding through base rates, Transportation and Sales customers would share in supporting this effort.

CUSTOMER SERVICES

The Company's Customer Services Operation engages in over 95 million customer transactions per year, about half of which are related to our gas operations. This includes over 5 million phone calls to our Inquiry Centers, over 2 million one-on-one transactions at our Customer Service offices, over 40 million meter readings at the customers' premises, and over 600 thousand collection related transactions. Over 1,400 employees are working on the Customer Service Operations side of the business, serving both electric and gas needs. Our Customer Service Operations group won the Silver Award from Quality New Jersey in 2000 for overall excellence in their processes in relationship management with customers, including safety.

The Company's two Inquiry Centers handle approximately 2 million gas-related calls per year. Recent improvements to the Customer Service Call Management System include menu options to direct calls to specific operator groups and dedicated "800" number lines for gas emergency calls. Call monitoring is extensively used to improve the quality of our customer transactions, and to provide feedback to our representatives on how to handle difficult situations, especially during cold weather and storm events. We have installed expanded capabilities in our communications infrastructure to handle intermittently high volumes of calls, and have effectively improved our service level on telephone service to an average of a 30 second wait for response. We have recently developed a web site for inquiries and routine transactions, such as customer-read meter readings, and have seen a very large increase in customer use of internet technology to about 15,000 commercial interactions in the year 2000. We have also installed software that helps our inquiry personnel to retrieve data from our Customer System quickly when working with a customer on their account. With the rapidly changing industry, the Company continues to evaluate the effectiveness of the

Customer Information System, which is being used for all inquiries, credit, collections, and customer choice.

Our meter readers are charged with visiting and reading almost 1.7 million gas meters monthly, of which 75% are located indoors. We maintain keys for over 80,000 locations, demonstrating the high level of trust between our meter readers and our customers. One of our greatest concerns for meter readers is their safety, since they are often asked to enter dark basements or houses where animals or other hazards may be present. One of the Company's key safety initiatives is to get customers involved in safety awareness to help control hazards to our meter readers and service technicians that may need to work on their property. This program benefits our customers as well as our employees, extending safety awareness and accident prevention to include our customers' premises.

An additional 775 gas service technicians work very closely with our call centers to respond promptly to leaks and other emergency calls, and are the first responders to gas leaks, both outside and inside customers' premises. They perform a variety of behind the meter gas safety services associated with appliances and customer gas piping systems in a responsive and thorough manner, as well as supporting on-site gas metering for our 1.6 million gas customers. In the year 2000, our service technicians provided safety services to over 400,000 gas appliances and restored service to over 22,000 customer premises The full talents, training and dedication of this group of technicians were highlighted during the storm restoration from Hurricane Floyd when widespread areas were hit with flooding, and expeditious and thorough piping and appliance repair needed to take place.

The Company has been able to improve productivity in providing the customer services described above through a number of process improvements including: Home Based Reporting, implementation of the GSIMS, Planning/Scheduling/Forecasting processes and the establishment of a Parts Distribution Center. In addition, the appliance repair services offered by this group have allowed the company to recoup some of the fixed costs associated with keeping persons on duty around the clock to respond to emergencies by filling in the down time, especially during warmer weather, with productive work that brings additional revenues into the Company and reduces overall costs to customers.

CONCLUSION

In my judgment, gas operations at PSE&G are conducted properly, efficiently and in such a manner as to provide safe, adequate and reliable service to our customers. We have made numerous improvements in the technology and infrastructure of our gas business since our last gas rate case decision in order to provide the service levels that our customers have come to expect. Our gas distribution business is a vital component of the State's economic infrastructure and our request supports the need to continue to provide a gas distribution system and organization that assures our customers of continued safe, reliable, and responsive service.