Exhibit No.: 11
Issue: Environmental Response Fund; Gas Storage Inventory; Bad Debts
Witness: Michael R. Noack
Type of Exhibit: Surrebuttal Testimony
Sponsoring Party: Missouri Gas Energy
Case No.: GR-2004-0209
Date Filed: June 14, 2004

MISSOURI PUBLIC SERVICE COMMISSION

MISSOURI GAS ENERGY

CASE NO. GR-2004-0209

SURREBUTTAL TESTIMONY

OF

MICHAEL R. NOACK

Jefferson City, Missouri

June 2004

SURREBUTTAL TESTIMONY OF MICHAEL R. NOACK
ON BEHALF OF
MISSOURI GAS ENERGY
GR-2004-0209

INDEX TO TESTIMONY

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Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Michael R. Noack, 3420 Broadway, Kansas City, Missouri.

Q. ARE YOU THE SAME MICHAEL R. NOACK WHO PREVIOUSLY SUBMITTED DIRECT, UPDATED DIRECT AND REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. I will address the rebuttal testimony of Staff witness Harrison and OPC witness Bolin related to the environmental response fund, the rebuttal testimony of OPC witness Bolin related to incentive compensation, the rebuttal testimony of Staff witness Imhoff related to increased bad debts and other cost increases resulting from the newly promulgated denial of service rule, and to the rebuttal testimony of Staff witness Oligschlaeger related to the historical MGE earnings analysis and annual operating and maintenance ("O&M") cost per customer comparisons.

Environmental Response Fund

Q. PLEASE DESCRIBE THIS ISSUE.

A. Both the Staff (by way of the testimony of Mr. Harrison) and OPC (by way of the testimony of Ms. Bolin) oppose MGE's proposal to implement a mechanism to address the ongoing regulatory and ratemaking treatment of costs associated with former manufactured gas plant ("MGP"). The basis of their opposition can be paraphrased as follows:

a. OPC and the Staff allege that the asset purchase agreement pursuant to which Southern Union acquired the Missouri property from Western Resources, Inc., in 1994 somehow disclaims rate recoverability of MGP costs (Harrison Rebuttal, pp. 9-10; Bolin Rebuttal, pp. 20-22);

b. the Staff alleges that MGP costs are not known and measurable (Harrison Rebuttal, p. 10) and OPC alleges that MGP costs may be potentially recoverable from other entities (Bolin Rebuttal, pp. 23 and 25-26);

c. the Staff alleges that the environmental response fund proposed by MGE could constitute single-issue and retroactive ratemaking (Harrison Rebuttal, p. 10);

d. the Staff alleges that the environmental response fund proposed by MGE is flawed in that it provides automatic rate recovery of MGP costs and therefore reduces the incentive for MGE to seek recovery of cots from other entities (Harrison Rebuttal, pp. 10-11) and OPC alleges that the environmental response fund proposed by MGE is flawed in that it permits MGE to retain a portion of recoveries or contributions obtained from other entities (Bolin Rebuttal, pp. 28-29).

e. OPC alleges that MGE did not actually expend any funds during the test year on MGP matters (Bolin Rebuttal, pp. 23-24);

f. OPC alleges that the "used and useful" principle precludes recovery of MGP costs (Bolin Rebuttal, pp. 24-25);

g. OPC alleges that customers have already reimbursed the company for MGP costs (Bolin Rebuttal, pp. 26-27); and

I will discuss and refute each of these allegations in turn below.

a. The 1994 Asset Purchase Agreement Does Not Preclude Rate Recovery of MGP Costs

Q. DOES THE 1994 ASSET PURCHASE AGREEMENT BETWEEN SOUTHERN UNION AND WESTERN RESOURCES PRECLUDE RATE RECOVERABILITY OF MGP COSTS?

A. No. In fact the asset purchase agreement specifically requires Southern Union to seek rate recovery of MGP costs before it may seek recovery from Western Resources. (Harrison Rebuttal, Schedule 1-5, section (iii)). Moreover, if Southern Union had agreed to forego recovery of MGP costs from Missouri customers any such agreement most certainly would have been reflected in the Stipulation and Agreement approved by the Commission in the course of authorizing Southern Union's acquisition of the Missouri property. No such agreement is reflected in that document and no party has made any allegation that Southern Union has made any such agreement.

b. MGP Costs Need Not Be Known and Measurable to be Included in Rates

Q. DO YOU AGREE THAT MGP COSTS MUST BE KNOWN AND MEASURABLE TO BE INCLUDED IN RATES?

A. No. The environmental response fund proposed by MGE as contained in my direct testimony would segregate all revenues—including a share of any contributions toward MGP costs the Company is able to obtain from other entities—collected for these costs into an interest bearing trust account. To the extent that monies in the account are not spent, any such amounts can be credited to the benefit of customers when the Commission deems it appropriate. However, it must be recognized that approximately $9.3 million has been spent by MGE on MGP activities since February 1994, and as explained in the rebuttal testimony of MGE witness Alan Fish, MGE continues to believe that it will be necessary to incur additional MGP costs in the future.

c. Sound Policy Reasons Support Implementation of an Environmental Response Fund

Q. DO YOU AGREE WITH STAFF WITNESS HARRISON THAT THE ENVIRONMENTAL RESPONSE FUND PROPOSED BY MGE COULD CONSTITUTE PROHIBITED SINGLE-ISSUE AND RETROACTIVE RATEMAKING?

A. No. The environmental response fund proposed by MGE is essentially a tracking mechanism designed to ensure that shareholders and customers are neither benefited nor disadvantaged by a mismatch between MGP costs included in rates and MGP costs actually incurred. Although not a traditional ratemaking mechanism in Missouri, a tracking mechanism is appropriate for MGP costs because although the incurrence of such costs is certain, the precise timing and amount of such costs is not presently known. Many jurisdictions have adopted similar mechanisms for the regulatory and ratemaking treatment of MGP costs, presumably for those very reasons. Schedule MRN-1 attached hereto shows just a few examples of jurisdictions which have adopted mechanisms for the regulatory treatment of MGP costs similar to the environmental response fund proposed by MGE. The environmental response fund proposed by MGE is essentially an accounting authority order, as Staff witness Harrison appears to recommend at page 11 of his rebuttal testimony, with the added feature of funding. Funding serves the beneficial purposes of mitigating rate shock in the event significant MGP costs are incurred in the future and also promotes intergenerational equity concepts by spreading cost recovery over a wider base of customers. Therefore, because of the specific design features of the environmental response fund proposed by MGE, I do not believe it constitutes prohibited single-issue or retroactive ratemaking.

d. The Environmental Response Fund Provides Appropriate Incentives for MGE to Minimize Cost Recovery from Customers

Q. **STAFF WITNESS HARRISON ALLEGES THAT THE ENVIRONMENTAL RESPONSE FUND PROVIDES AUTOMATIC RECOVERY OF MGP COSTS AND THEREFORE REDUCES THE INCENTIVE FOR MGE TO SEEK RECOVERY OF SUCH COSTS FROM SOURCES OTHER THAN CUSTOMERS AND OPC WITNESS BOLIN ALLEGES THAT THE ENVIRONMENTAL RESPONSE FUND INAPPROPRIATELY PROVIDES AN INCENTIVE OPPORTUNITY TO THE COMPANY. DO YOU AGREE?**

A. No. Mr. Harrison apparently ignores three critical features of MGE's proposal that provide very real incentives for MGE to minimize cost recovery from customers. First, sub-paragraph (a) includes the following requirement: "The Company will use best efforts to satisfy its obligation to minimize the Environmental Response Costs charged to the fund consistent with applicable regulatory requirements and sound environmental policies and to minimize litigation costs that may arise." Second, the sharing between customers and shareholders of contributions and/or recoveries obtained from other parties toward MGP costs as proposed in sub-paragraph (a) provides the Company with an opportunity to generate benefits for shareholders and customers from successful pursuit of such contributions. Contrary to the allegations of Ms. Bolin, successful pursuit of such contributions provide benefits to both the Company and its customers, so a sharing of such contributions is entirely appropriate. Third, sub-paragraph (c) specifically provides that the right to review costs charged to the environmental response fund is retained. All of these items make sure that the Company will use its best efforts to minimize MGP costs sought to be recovered from customers.

Q. **HAS THE MISSOURI PUBLIC SERVICE COMMISSION EVER ENDORSED A PLAN OF REIMBURSEMENT OF ENVIRONMENTAL COSTS AND A SHARING OF INSURANCE PROCEEDS BETWEEN CUSTOMER AND SHAREHOLDER?**

A. Yes. The stipulation and agreement in FERC Docket No. RP93-109-000 called for Williams Natural Gas Company, now Southern Star Central, to recover annual environmental costs of $1,700,000 and to continue to split insurance recoveries between customer and shareholder on a 90% customer and 10% shareholder basis. On February 16, 2001, the "Comments of the Missouri Public Service Commission in support of Stipulation and Agreement" was filed. The cover letter and the Comments are attached as Schedule MRN-2.

e. Significant MGP Expenditures Were Made During the Test Year

Q. **OPC WITNESS BOLIN ALLEGES THAT MGE DID NOT EXPEND FUNDS ON MGP ACTIVITIES DURING THE TEST YEAR. IS THIS ACCURATE?**

A. No. As I stated in my direct testimony, MGE spent $6.32 million on MGP activities during the test year. The fact that these expenditures are recorded on the Southern Union corporate books rather than the MGE books is irrelevant because as an operating division of Southern Union, my understanding is that MGE and Southern Union are effectively one and the same entity.

f. The "Used and Useful" Principle Does Not Preclude Recovery of MGP Costs

Q. OPC WITNESS BOLIN ALLEGES THAT THE "USED AND USEFUL" PRINCIPLE PRECLUDES RECOVERY OF MGP COSTS. DO YOU AGREE?

A. No. My understanding is that only used and useful items are to be included in rate base on which a return may be earned for purposes of calculating revenue requirements. MGP costs are not rate base items, but expense items, and as such I do not believe the used and useful concept has any applicability to determining their recoverability through rates. As an example, utility companies will on occasion retire plant items prior to such plant items being fully depreciated. In such situations it is not at all uncommon for the Commission include in the calculation of rates an amount reflecting the amortization to expense of the undepreciated plant balance associated with the retired property. Thus, even though the property has been retired and is no longer used and useful, expense associated with that property is nevertheless included in the calculation of rates.

g. Customers Have Not Already Reimbursed the Company for MGP Costs

Q. OPC WITNESS BOLIN ALLEGES THAT CUSTOMERS HAVE ALREADY REIMBURSED THE COMPANY FOR MGP COSTS THROUGH THE RETURN ON EQUITY INCLUDED BY THE COMMISSION IN CALCULATING PAST RATES. DO YOU AGREE?

A. No. This allegation makes no sense at all to me. If true, one could also say that electric utilities should not be permitted to recover extraordinary costs caused by extreme weather events such as ice storms because past equity returns compensated the utility for such risks. Such an argument is clearly nonsense. As a matter of fact, the Company has expended approximately $9.3 million in MGP costs since 1994 that have not been borne by customers.

Q. DO YOU HAVE ANY OTHER COMMENTS TO MAKE?

A. Yes. The request which MGE has made in this case is very similar to a plan approved in Massachusetts in 1990. Attached as Schedule MRN-3 is the order approving a settlement in the generic case involving the ratemaking treatment of the costs of investigating and remediating matters associated with the manufacture of gas during the period 1822-1978. The order addresses most of the concerns of both OPC witness Bolin and Staff witness Harrison. In addition to setting up a mechanism to recover costs, the Order also approves a sharing mechanism between customers and shareholders of 50/50 of net insurance proceeds.

Gas Storage Inventory

Q. IS GAS STORAGE INVENTORY STILL AN ISSUE IN THE CASE?

A. No, I do not believe so. Agreement was reached between Staff and MGE to price the average volumes in inventory at a price of $5.68 per MMBtu. This agreement results in an increase to Staff's rate base of $11,394,748 and an increase in the Staff revenue requirement of $978,475 (at the mid-point Staff rate of return).

Bad Debts-Cost Increases Resulting From New Denial of Service Rule

Q. STAFF WITNESS IMHOFF CLAIMS IN HIS REBUTTAL TESTIMONY THAT THE ESTIMATED $750,000 IMPACT OF THE NEW DENIAL OF SERVICE RULE ON MGE ASSUMES THAT THE NEW RULE PRECLUDES MGE FROM COLLECTING ON PAST DUE ACCOUNTS. HOW DO YOU RESPOND?

A. I know what assumptions were the basis for the estimate I made. The estimated impact on MGE that I made contains no such assumption, so Staff witness Imhoff is wrong.

This new rule will preclude denial of service to an applicant based on the bad debt of someone who is going to live with the applicant. This will have a two-fold impact on MGE by both reducing potential revenue and increasing bad debt expenses. It will reduce potential revenue by eliminating a collection tool that has proven effective. The new rule will increase costs in two primary ways: 1) bad debts will rise; and 2) collection costs will rise. Under the previous procedure, MGE was able to utilize its tariff provision to the benefit of its customers. That is because the tariff procedure provided a cost-effective means of collecting overdue bills that were legitimately owed to MGE. Because MGE, under the new rule, will no longer be able to require payment or payment arrangements by the bad debt holding roommate before initiating service, a greater number of accounts will now have to be referred to outside collection agents. On average, only about 35% of amounts referred to outside collectors actually gets paid. Moreover, outside collection costs typically amount to approximately 19% of the amount recovered. Therefore, the enactment of the new rule forces upon MGE a less efficient and more costly procedure for collection of some overdue bills for gas service. As I understand it, the new rule will take effect on November 1, 2004, so we are beyond the point of arguing over whether the policy underlying the change is good or bad. We are at the point of trying to determine what the financial impact on MGE is going to be so that rates can be set to allow MGE to recover this newly imposed increased cost of doing business.

Q. HAS THE STAFF UNDERTAKEN ANY ANALYSIS TO ASCERTAIN THE IMPACT OF THE NEW DENIAL OF SERVICE RULE ON MGE'S BAD DEBTS?

A. No, according to the Staff's response to MGE data request number 0130 (Schedule MRN-4)

Historical MGE Earnings Analysis and O&M Cost Comparisons

Q. ON PAGES 8-11 OF HIS REBUTTAL TESTIMONY STAFF WITNESS OLIGSCHLAEGER DISCUSSES THE HISTORICAL MGE EARNINGS ANALYSIS YOU PRESENTED ON SCHEDULE G-4 OF YOUR DIRECT TESTIMONY. WHAT CONCLUSION DOES MR. OLIGSCHLAEGER REACH?

A. Although offering some mild criticism of my analysis, which I will address later, Mr. Oligschlaeger does not disagree with the central point of the analysis, namely that MGE's actual earnings have consistently fallen short of its Commission-authorized return levels. Specifically, Staff witness Oligschlaeger acknowledges MGE's consistent historical earnings shortfalls when he states:

> Q. Having made these points concerning MGE's earnings analysis, **do you disagree that MGE has had a tendency to underearn** in its short history to date?
>
> A. **No.** Given the fact that MGE has added much plant in service to its rate base in recent years, and the nature of the ratemaking process in Missouri, **that phenomenon is exactly what would be expected to happen.**

(emphasis supplied)

Q. WHAT CRITICISMS HAS MR. OLIGSCHLAEGER OFFERED REGARDING YOUR ANALYSIS OF MGE'S HISTORICAL EARNINGS?

A. In concluding that I have understated MGE's actual earnings levels, Staff witness Oligschlaeger offers three technical criticisms of the analysis:

1. my use of "end of period" rate base amounts versus annual average rate base;

2. my use of actual revenues and expenses versus "normalized" revenues and expenses; and

3. my omission of deferred income taxes as an offset to rate base.

Interestingly, Mr. Oligschlaeger provided no alternative analysis of MGE's historical earnings levels.

Q. HOW DO YOU RESPOND TO THESE CRITICISMS?

A. As to items 1 and 3 above, I do not disagree with Mr. Oligschlaeger; however, incorporating those changes in the analysis does not significantly change the overall results, as can be seen on Schedule MRN-5.

As to item 2, I disagree strenuously with using "normalized" revenues and expenses to ascertain actual historical earnings levels. Because the ratemaking process is forward looking and seeks to forecast expected conditions during the period in the future when the rates will be in effect, revenue and expense levels are "normalized" in an effort to reflect expected or "normal" conditions. The ascertainment of actual earnings experience, on the other hand, is a purely historical analysis that looks backward to quantify earnings actually experienced over a given time frame. Consequently, "normalized" revenues and expenses cannot be used to determine actual earnings levels. For example, if MGE's employees are required to work more overtime than normal in a given year, MGE must pay those employees for all overtime worked regardless of the fact that such overtime exceeded normal. Actual earnings are based on actual expenses and revenues, not forecasts or estimates as to what a "reasonable" or "expected" or "normal" level of such revenues or expenses might be in the future.

Q. REFERRING BACK TO SCHEDULE MRN-5, HAS MGE HAD RATE INCREASES GO INTO EFFECT DURING THE PERIOD COVERED ON MRN-5?

A. Yes. MGE had increased rates become effective on March 21, 1997 in case number GR-96-285, September 2, 1998 in case number GR-98-140 and August 6, 2001 in case number GR-2001-0292.

Q. DID MGE EARN THE COMMISSION AUTHORIZED RETURN IN THE FISCAL YEAR IMMEDIATELY FOLLOWING ANY OF THE ABOVE MENTIONED RATE INCREASES?

A. No.

Q. ON PAGES 3-8 OF HIS REBUTTAL TESTIMONY STAFF WITNESS OLIGSCHLAEGER DISCUSSES THE OPERATING AND MAINTENANCE ("O&M") COST COMPARISON BETWEEN MGE AND CERTAIN OTHER MISSOURI GAS UTILITIES YOU PRESENTED ON SCHEDULE G-1 OF YOUR DIRECT TESTIMONY. WHAT CONCLUSION DOES MR. OLIGSCHLAEGER REACH?

A. Although offering some criticism of my analysis, which I will address later, and some historical perspective that is not particularly relevant to a comparison of recent O&M costs, Mr. Oligschlaeger does not disagree with the central point of the analysis, namely that MGE's O&M costs are lower than peer companies in the State. Specifically, Staff witness Oligschlaeger acknowledges MGE's consistently lower O&M costs when he states:

> Q. Do you agree with Mr. Oglesby's conclusion that MGE's O&M expenses are lower than Laclede Gas Company's (Laclede's), AmerenUE's and Aquila Inc's (Aquila's) gas O&M expenses, when measured on a per customer basis?
>
> A. I do not disagree with the data shown on page 7 of Mr. Oglesby's direct testimony [which is drawn from Noack Direct, Schedule G-1]. * * *

Q. MR. OLIGSCHLAEGER INDICATES, ON PAGES 3-4 OF HIS REBUTTAL TESTIMONY, THAT CAUTION SHOULD BE USED WHEN MAKING DIRECT COST COMPARISONS BETWEEN DIFFERENT UTILITIES. HOW DO YOU RESPOND?

A. I agree. No two companies are identical. However, the fact remains that the Missouri gas operations of Laclede, AmerenUE and Missouri Public Service (also known as "Aquila") are all subject to the regulatory authority and regulatory requirements of the Missouri Public Service Commission just like MGE's operations. Moreover, while the operations of these companies are not identical, they are subject to many similar economic conditions since all of the operations about which the comparison is being made are located within the State of Missouri. Moreover, Laclede, AmerenUE and Missouri Public Service, like MGE, have filed and processed requests for general rate increases in the recent past. In addition, the analysis compares O&M cost performance over a period of several years, not just one or two years, which eliminates the chance that MGE's significant advantage from an O&M cost perspective is not being driven by an extraordinary or non-recurring item. As a consequence of these factors, I believe it is reasonable to conclude that MGE consistently outperforms Laclede, AmerenUE and Missouri Public Service from the analysis contained in Schedule G-1 in my direct testimony.

Q. DO YOU HAVE ANY MORE CURRENT INFORMATION THAN THE DATA INCLUDED IN YOUR DIRECT TESTIMONY?

A. Yes. In April of this year, annual reports were filed by MGE and Laclede. Those annual reports indicate that for calendar year 2003, MGE's annual O&M cost per customer was $141.15 and Laclede's annual O&M cost per customer was $212.17. More recent annual reports were not available for AmerenUE and Aquila (Missouri Public Service).

Q. MR. OLIGSCHLAEGER ASSERTS THAT ATMOS ENERGY CORPORATION HAD LOWER O&M COSTS THAN MGE IN 2003 AND SHOULD HAVE BEEN INCLUDED IN YOUR ANALYSIS. HOW DO YOU RESPOND?

A. For 2003, Mr. Oligschlaeger's analysis shows the Atmos annual O&M cost per customer to be $8 lower than MGE's. What Mr. Oligschlaeger leaves unstated in his testimony is that while MGE is shown as having $6,934,982 in Joint and Common Costs for calendar year 2003 (amounting to approximately $13.92 per customer), no such costs are included in the calculation of the Atmos annual O&M cost per customer for calendar year 2003. Therefore, Mr. Oligschlaeger is not comparing "apples to apples." I would expect that 1) Atmos has Joint and Common Costs that it would seek to recover through rates but that are not shown in its FERC Form 2 (the annual report form filed with the Commission) and 2) the Atmos Joint and Common Costs for calendar year 2003 likely amounted to at least $8 annually per customer such that reflecting such costs in the analysis would eliminate any O&M cost advantage for Atmos.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes, at this time.

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Missouri Gas Energy's Tariff Sheets Designed to Increase Rates for Gas Service in the Company's Missouri Service Area.	))))	Case No. GR-2004-0209

AFFIDAVIT OF MICHAEL R. NOACK

STATE OF MISSOURI)
) ss.
COUNTY OF JACKSON)

Michael R. Noack, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Surrebuttal Testimony in question and answer form, to be presented in the above case; that the answers in the foregoing Surrebuttal Testimony were given by him; that he has knowledge of the matters set forth in such answers; and that such matters are true and correct to the best of his knowledge and belief.

Michael R. Noack

MICHAEL R. NOACK

Subscribed and sworn to before me this 14th day of JUNE 2004.

Kim W. Henzi

Notary Public

My Commission Expires: Feb. 3, 2007

Kim W. Henzi
Notary Public - Notary Seal
State of Missouri
Jackson County
My Commission Expires Feb. 3, 2007

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE REQUEST BY NORTHWESTERN PUBLIC SERVICE COMPANY FOR TARIFF REVISIONS	)	**ORDER APPROVING TARIFF REVISIONS AND APPROVING SETTLEMENT**
	)	**NG96-015**

On July 2, 1996, Northwestern Public Service Company of Huron, South Dakota (NWPS), filed with the Public Utilities Commission (Commission) the following proposed tariff revisions in its natural gas rate book:

Section No.1, 26th Revised Sheet No. 1

3rd Revised Sheet No. 2

Section No. 2, 6th Revised Sheet No. 1

5th Revised Sheet No. 2

Section No. 3, 15th Revised Sheet No. 1

1st Revised Sheet No. 2

5th Revised Sheet Nos. 3.1, 6.1, and 9

2nd Revised Sheet Nos. 3.2, 3.3, 4.2, 6.3, and 13.1

6th Revised Sheet Nos. 4.1 and 9c

3rd Revised Sheet Nos. 6.2, 7, and 11

Original Sheet Nos. 6.4, 6.5, 6.6, 6.7, 6.8, 6.9, 6.10, and 6.11

10th Revised Sheet No. 8

21st Revised Sheet No. 9a

19th Revised Sheet No. 9b

40th Revised Sheet No. 11a

Section No. 5, 2nd Revised Sheet Nos. 1 and 1a

Original Sheet Nos. 5.2, 6.1, 6.2, 6.3, 6.4, 6.5, 6.6, 6.7, 6.8, 7.1, 7.2, and 7.3

Section No. 6, Original Sheet Nos. 22, 23, 24.1, 24.2, 24.3, 25.1, 25.2, 25.3, 26, 27, and 28

On July 10, 1996, PAM Natural Gas, LLC (PNG) filed a petition to intervene in this matter. Intervention was granted

PNG on July 17, 1996. Settlement was reached between the parties and staff of the Commission. A hearing on whether the settlement should be approved was held on November 5, 1996, at which time evidence on the tariff revisions and true-up of the final costs of the manufactured gas site remediation was presented. Approval was requested for implementation effective December 1,1996.

At an ad hoc meeting of November 12,1996, the Commission considered approval of the tariffs.

The Commission finds that it has jurisdiction in this matter pursuant to SDCL Chapter 49-34A, specifically 49-34A-4, 49-34A-6, 49-34A-8, 49-34A-10 and 49-34A-12. Further, the revisions, based upon the settlement reached between the parties and Commission staff, are just and reasonable and shall be approved subject to the following condition: NWPS shall make every effort to recover the manufactured gas plant remediation costs from whatever sources are available and shall report to the Commission biannually, starting six months from the date of this Order, as to the status of its efforts in collection of those costs.

As the Commission's final decision in this matter, it is therefore

ORDERED, that the Settlement Agreement reached between the parties and Commission staff is incorporated herein by reference and is approved; and it is further

ORDERED, that NWPS' revised tariffs as described above are approved upon the condition regarding reporting of collection efforts on the manufactured gas plant remediation costs and they shall be effective for service rendered on and after December 1, 1996.

Dated at Pierre, South Dakota, this 25th day of November, 1996.

CERTIFICATE OF SERVICE

The undersigned hereby certifies that this document has been served today upon all parties of record in this docket, as listed on the docket service list, by facsimile or by first class mail, in properly addressed envelopes, with charges prepaid thereon.

By:______________________________

Date:______________________________

(OFFICIAL SEAL)

BY ORDER OF THE COMMISSION:

____

KENNETH STOFFERAHN, Chairman

____

JAMES A. BURG, Commissioner

____

LASKA SCHOENFELDER, Commissioner

South Dakota Public Utilities Commission

WEEKLY FILINGS

For the Period of November 21, 2002 through November 27, 2002

If you need a complete copy of a filing faxed, overnight expressed, or mailed to you, please contact Delaine Kolbo within five business days of this report. Phone: 605-773-3705 Fax: 605-773-3809

NATURAL GAS

NG02-010 In the Matter of the Filing by NorthWestern Energy for Approval of Tariff Revisions.

Application by NorthWestern Energy for approval of revisions to its natural gas tariff to terminate Manufactured Gas Plant cost recovery. In Docket NG96-015, NorthWestern Energy filed to make numerous changes to its natural gas tariff, including recovery of costs associated with manufactured gas plant clean-up. The result of the filing was a per therm surcharge approved by the Commission to recover the manufactured gas plant costs. NorthWestern Energy has now completed recovery of the related costs and now requests discontinuance of the surcharge. NorthWestern proposes to pass back an associated over-recovery to customers through the commodity gas cost true-up.

Staff Analyst: Dave Jacobson
Staff Attorney: Karen Cremer
Date Docketed: 11/26/02
Intervention Deadline: 12/13/02

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Southern Star Central Gas Pipeline, Inc.) Docket No. RP93-109-020

**PROTEST AND NOTICE OF INTERVENTION
OF THE
MISSOURI PUBLIC SERVICE COMMISSION**

Pursuant to Rules 211 and 214(a)(2) of the Federal Energy Regulatory Commission's ("Commission") Rules of Practice and Procedure, 18 C.F.R. §385.211 and §385.214(a)(2), the Missouri Public Service Commission ("MoPSC") hereby submits its Protest and Notice of Intervention in the captioned docket. In support thereof, the MoPSC states as follows:

I. SERVICE

Service of orders, pleadings, and other communications should be directed to the following persons:

Lera L. Shemwell Senior Counsel Missouri Public Service Commission P.O. Box 360 Jefferson City, MO 65102 573-751-7431 573-751-9285 (fax)	David D'Alessandro Kelly A. Daly John E. McCaffery Stinson Morrison Hecker, LLP 1150 18th Street, NW, Suite 800 Washington, D.C. 20036-3816 202-785-9100 202-785-9163 (fax)

II. DESCRIPTION OF FILING

On November 20, 2003, Southern Star Central Gas Pipeline, Inc. ("Southern Star") submitted its annual report of environmental proceeds received from third-party insurers during the twelve months ended September 30, 2003. This annual report is required by Article III.D. of the Stipulation and Agreement dated January 31, 2001 in Docket No. RP93-109-017. Southern

0312025021 Received FERC OSEC 12/02/2003 04:01:00 PM Docket# RP93-109-000

Star states it received no such proceeds during this 12-month period, therefore it is making no refunds this year.

III. INTERVENTION

The intervenor's legal name is the Public Service Commission of the State of Missouri. The MoPSC is a governmental agency created under the laws of the State of Missouri, § 386.040 MO. REV. STAT. (2002 SUPP) with jurisdiction to regulate rates and charges for the sale or distribution of natural gas to consumers in the State, § 386.250 MO. REV. STAT. (2002 SUPP). It is, therefore, a "State Commission" within the meaning of Section 1.101(k) of the Commission's general regulations.

The MoPSC wishes to intervene in this proceeding to protect its interests as they may appear and generally to insure that the citizens of Missouri can receive safe, adequate, and reliable natural gas service at reasonable prices with reasonable terms and conditions. Southern Star currently serves seven investor-owned utility companies regulated by the MoPSC, i.e., Missouri Gas Energy, a division of Southern Union Company; Laclede Gas Company; Aquila, Inc., d/b/a Aquila Networks – MPS (f/k/a Missouri Public Service, a division of UtiliCorp United, Inc.); Southern Missouri Gas Company, L.P.; Greeley Gas Company, a division of Atmos Energy; Kansas City Power & Light Company; and The Empire District Electric Company. Accordingly, the MoPSC has a direct and unique interest in this proceeding and is entitled to party status upon filing this Notice of Intervention pursuant to 18 CFR §385.214(a)(2).

IV. PROTEST

- **Southern Star has an apparent conflict of interest with respect to pursuing claims against certain third-party insurers.**

By way of background – While the noted January 2001 Stipulation and Agreement fine-tuned the reporting mechanism for this refund procedure, the requirement for revenue crediting and reporting was established as a result of litigation in the Docket No. RP93-109 rate case. 73 FERC ¶63,015 (1995) and 77 FERC ¶61,277 (1996). In that case, the Commission permitted the pipeline to include a significant amount of environmental cleanup costs in the O&M expenses contained in its base rates. However, to ensure that the pipeline had an incentive to pursue recovery of these costs from third parties (such as a liability insurance carrier or suppliers of the contaminated material), while compensating pipeline ratepayers in a fair way and setting up an equitable system of sharing the costs of WNG's litigation, the Commission prescribed the present annual revenue crediting mechanism. It directed the pipeline to deduct the expenses of litigation from any third parties recoveries; while refunding 90% of the net recoveries to ratepayers, the pipeline is permitted to retain 10% of any net amounts collected.[1]

Despite the pipeline's testimony that recovery of costs from third parties would be extremely unlikely, the Commission's prescription has resulted in the following amounts being recovered:

Docket No.	Amount
RP93-109-016	$2,358,720
RP93-109-017	1,186,357
RP93-109-018	437,231
RP93-109-019	17,118
RP93-109-020	0

The recoveries to-date have come from 2-3 different insurance companies.

However, since the new owner of Southern Star,[2] AIG Highstar Capital, LP, is affiliated with AIG (American International Group),[3] one of the world's largest insurance companies,

[1] Given this mechanism, parties agreed to continue to include certain environmental costs in the base rates for Southern Star's existing rates in Docket No. RP95-136. See Article V, Section C of the November 27, 1996 Stipulation and Agreement, approved 78 FERC ¶61,257 (March 7, 1997).

[2] Effective November 16, 2002, Southern Star Central Gas Pipeline, Inc. (formerly known as Williams Gas Pipeline Company, Inc.) was purchased by Southern Star Central Corp. Southern Star Central Corp. is wholly owned by AIG Highstar Capital, L.P. (Footnote 1 of Southern Star's 2002 FERC Form 2, p. 122.)

[3] http://www.aig.com/GW2001/SiteMap/0,5023,,00.html

MoPSC believes Southern Star now has a disincentive for pursuing recovery from a number of remaining insurance policies under which additional claims could or should be made. In reviewing the list of policies and insurers,[4] which Williams had prepared during its rate case, it appears at least five of the remaining insurance companies are associated in someway with AIG. Even if an unaffiliated insurance company is responsible for a potential payout under a past or present insurance policy held by Southern Star (or a predecessor), there is likely an informal understanding or code of conduct among insurance companies that discourages pursuit of such indemnifications from another insurance company.

Given the present conflict of interest, the MoPSC requests the Commission take the following actions.

1. Require Southern Star, to prepare and submit a written report, within 45 days, to the Commission and interested customers and state commissions, which:

    a. summarizes the actions taken by the pipeline to-date for each of the insurance policies previously identified as potential sources for claims/settlements of costs associated with the pipelines environmental cleanup responsibilities;

    b. identifies each policy under which an insurance company affiliated with AIG would be potential liable payment of an indemnification claim; and

    c. identifies those policies under which it intends to pursue a claim and/or settlement of a claim for indemnification.

    d. identifies the contact person(s) who is/are most knowledgeable about the pipeline's efforts to pursue recovery of environmental cleanup costs from third parties.

2. Require Southern Star to make, simultaneous with the above report, all related documents (including but not limited to – all underlying insurance policies and internal and external correspondence relating to the pipeline's inquiry and/or claim(s)

[4] Out of an abundance of caution (so as not to affect any potential negotiations or litigation between the pipeline and the various insurers), the policy listing (which was obtained during a previous rate case) along with information as to which companies/policies collections to-date have come, is being forwarded to the Commission as a confidential attachment.

concerning the indemnification of environmental cleanup costs) available to the Commission and interested customers and state commissions for their review. (This should include those policies and related correspondence associated with insurance recoveries already received.);

3. Within 60 days of receiving Southern Star's written report, parties shall file with the Commission any comments, concerns, and suggestions with respect to Southern Star's handling of third party insurance claims for environmental cleanup costs.

WHEREFORE, the MoPSC respectfully requests the Commission establish the above-described discovery procedures in an effort to evaluate and mitigate the existing conflict of interest which exists with respect to Southern Star's pursuit of claims against certain third-party insurers for environmental cleanup costs.

Respectfully submitted,

Lera L. Shemwell

Lera L. Shemwell
Senior Counsel
Missouri Public Service Commission
P. O. Box 360
Jefferson City, Missouri 65102
(573) 751-7431

CERTIFICATE OF SERVICE

Pursuant to Rule 2010 of the Commission's Rules of Practice and Procedure, I hereby certify that I have this day served a copy of the foregoing document on all persons designated on the official service list compiled by the Secretary in this proceeding dated at Jefferson City, Missouri, this 2nd day of December, 2003.

Lera L. Shemwell

Lera L. Shemwell

ORDINANCE 859

AN ORDINANCE OF ASHLAND, NEBRASKA, ESTABLISHING CLASSES AND RATES TO BE CHARGED FOR NATURAL GAS SERVICE WITHIN ASHLAND, NEBRASKA, REPEALING RATE ORDINANCE NO. 776; AND PROVIDING FOR AN EFFECTIVE DATE.

BE IT ORDAINED BY THE MAYOR AND CITY COUNCIL OF ASHLAND, NEBRASKA:

SECTION 1. That Natural Gas Rate Ordinance No. 776, and any amendments thereto, of Ashland, Nebraska, be amended to read as follows:

Section 1. Rate Schedule, Monthly Charge; Heat Value, Basis of; Adjustment; Penalty for Delinquency; Adjustment for Cost of Purchased Gas and Taxes: Grantee, its successors or assigns, shall file and make effective initially a schedule of rates for gas service and shall furnish gas at the schedule of rates hereafter set forth or at such other reasonable rates as my be hereafter established from time to time under the Nebraska Municipal Natural Gas Regulation Act, Neb. Rev. Stat. 19-4601, et seq. (1943)

(1) Firm Gas Service Rates

Availability - These rates are available only to domestic and commercial customers whose maximum requirements for natural gas are less than one hundred thousand (100,000) cubic feet per day. Grantee shall not be required to serve any customer at the following rates whose requirements amount to one hundred thousand (100,00) cubic feet or more per day. Grantee may negotiate price and other contract terms with customers whose natural gas requirements exceed fifty thousand (50,000) cubic feet per day.

Residential Customers Amount

Monthly Customer Charge $8.25 and Rate per Therm $.1153170

Commercial Customer

Monthly Customer Charge $13.25 and Rate per Therm $.1567016

The foregoing rates apply only when bills are paid on or before twenty (20) days after the monthly billing date. When not so paid, a one percent (1%) per month late fee will apply on the unpaid amount.

The above and foregoing rate shall be understood to be based upon natural gas of the British Thermal Unit (BTU) heating value of 1,000 BTUs per cubic foot of gas. If in any monthly period the average heating value of gas sold and delivered to the customers shall vary from 1,000 BTUs, then the volumes of gas billed to the customers during that month shall be multiplied by the factor of average hearing value in BTUs (1,000 to adjust for the variance.

Turn-On and Reconnect Fee

In addition to the other rates set forth in this Ordinance, Grantee may charge a $26.00 fee to initiate service ("turn-on fee") for each customer account and a $30.00 fee ("reconnect fee ") to reconnect service that has been discontinued or terminated for non-payment.

(2) Adjustment for Cost of Purchased Gas

In addition to the Firm Gas Service Rates set forth in Sub-Section (1) of this Ordinance, a separate charge per Therm may be made for the monthly cost of purchased gas in the Purchased Gas Cost Adjustment, if the Grantee (or any predecessor of Grantee) has properly filed a natural gas supply-cost-adjustment rate schedule pursuant to Neb. Rev. Stat. 19-4609(1). Such Purchased Gas Cost Adjustment shall be computed monthly pursuant to the natural gas supply-cost-adjustment rate schedule filed by the Grantee (or any predecessor of Grantee) pursuant to Neb. Rev. Stat. 19-4609

(1)

Any refund including interest thereon, if any, received by the Company from its supplier in respect of increased rates paid by Grantee subject to refund and applicable to natural gas purchased on a firm supply basis for resale in Rate Area Three shall be refunded to its gas customers in the form of credits on such customers' bills, or in cash, to the extent that such increased rates paid by the Company were passed on to such firm gas customers.

(3) Adjustment for Taxes

If, after the effective date of this ordinance, the business of Grantee in this Rate Area Three Municipality shall be subject to any taxes measured by its gross revenues from the operation of such business or the volume of such business or constituting a fee for carrying on such business, or in the event that (a) the rate of any such tax or (b) the amount of any such fee shall be increased after the effective date of this ordinance, the gas distribution company shall be entitled to increase its charges under the aforesaid rates so as to offset such imposition or impositions or such increase.

(4) General Rate Adjustment

The above provided for cost of purchased gas and tax adjustments are apart from and shall not in any manner limit or abridge either Grantee's right to request or the Mayor and City Council's authority to grant general rate adjustments increasing or decreasing such rates.

(5) Interruptible Gas Service Rate

Availability - This rate is available only on a contract basis to commercial or industrial customers whose use of natural gas is subject to interruption and periods of curtailment for reasons including but not limited to protecting the service of Grantee's firm gas users.

Rate - The rate of interruptible gas service shall be such rate as may be mutually agreed upon between the customer and that gas service company.

(6) Environmental Costs

Grantee may defer expenses reasonably incurred after December 1, 1999, as a result of monitoring, testing, clean-up, and the cost of reasonable efforts made by Grantee to recover remediation costs (hereinafter referred to generally as "manufactured gas plant" costs), if any, at the five manufactured gas plant sites allocated to Rate Area Three. No carrying costs will be calculated on any such balance of deferred manufactured gas plant costs. At the time of its next general rate case, Grantee may request recovery of any deferred manufactured gas plant costs and, if recovery is sought, must demonstrate in its rate application or sixty (60) days prior to the deadline for filing the Municipal Report that the manufactured gas plant costs were prudently incurred and reasonable, and that Grantee made reasonable efforts to recover remediation costs from potentially responsible third parties (which may include, but are not limited to, Grantee's predecessors in interest).

In any future rate application, Grantee will reduce any deferred manufactured gas plant costs by the proportional amount of manufactured gas plant costs previously recovered (i.e., $62,846 per year from December 1, 1999) from Rate Area Three as a credit to the deferred expenses allocated to Rate Area Three. Issues as to whether the deferred remediation costs were prudently incurred and reasonable, and whether the length of the amortization period for "past" manufactured gas plant costs requested by Grantee for recovering any such deferred remediation expenses is reasonable will be determined in the next rate case following the incurrence of such deferred manufactured gas plant costs.

Seventy-five percent (75%) of any funds (or the value of any other benefits) recovered from third parties by or on behalf of Grantee which are attributable to the remediation of any or all of the five manufactured gas plant sites allocated to Rate Area Three shall be credited to the deferred account. Grantee may keep twenty-five percent (25%) of any funds (or the value of other benefits) recovered from third parties.

(7) General Terms and Conditions

The General Terms and Conditions and associated Rate Schedule Tariff Sheets applicable to the natural gas service subject to the Municipal Natural Gas Regulation Act and provided for under this ordinance will be kept on file with the Municipal Clerk. The General Terms and Conditions and associated Rate Schedule Tariff Sheets may be changed from time to time by Grantee unless contrary provision is made by an ordinance adopted in the course of a future rate proceeding.

(8) Findings of Fact and Conclusions of Law

The Findings of Fact and Conclusions of Law, which were made a part of the official record at an Area Rate Hearing, are hereby adopted.

SECTION 2. Ordinance No.776 of Ashland, Nebraska and all other ordinances and parts of ordinances in conflict with the provisions of this ordinance are hereby repealed.

SECTION 3. This ordinance shall be in full force and effect from and after its passage, approval, and publication as required by law.

Passed and approved this 17th day of February, 2000.

____
Mayor

ATTEST:

____
Clerk

DG 02-167

NORTHERN UTILITIES, INC.

Winter 2002-2003 Cost of Gas

Order Approving Cost of Gas Rates
and Local Distribution Clause

O R D E R N O. 24,076

October 28, 2002

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

I. PROCEDURAL HISTORY

On September 16, 2002, Northern Utilities, Inc. (Northern) filed with the New Hampshire Public Utilities Commission (Commission) its Cost of Gas (COG) for the period November 1, 2002 through April 30, 2003 for Northern's natural gas operations in the Seacoast area of New Hampshire. The filing was accompanied by supporting attachments and the Direct Testimony of Joseph A. Ferro, Manager of Regulatory Policy, and Francisco C. DaFonte, Director of Gas Control.

On September 20, 2002, the Commission issued an Order of Notice setting the date of the hearing for October 16, 2002.

On October 2, 2002, Northern filed a Motion for Protective Order and Confidential Treatment concerning negotiated pricing terms that Northern claims are commercially sensitive and are not subject to public disclosure. This information was supplied in response to Staff Data Requests 1-1.c and 1-2.c.

On October 8, 2002, 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 to the OCA under RSA 363:28,II. There were no other intervenors in this docket.

On October 11, 2002, Northern filed a revised Cost of Gas for the 2002/2003 Winter Period.

On October 14, 2002, Staff filed the Direct Testimony and supporting schedules of Utility Analyst Robert J. Wyatt.

A duly noticed hearing on the merits was held at the Commission on October 16, 2002.

II. POSITIONS OF THE PARTIES AND STAFF

A. Northern

Northern witnesses Joseph A. Ferro and Francisco C. DaFonte addressed the following issues: 1) calculation of the COG rates; 2) reasons for the increase and customer bill impacts; and 3) the Local Distribution Adjustment Clause.

1. Calculation and Impact of the Firm Sales COG Rates

According to Northern's revised COG filing, the proposed 2002-2003 Winter average cost of gas residential firm sales rate of $0.7200 per therm is comprised of anticipated direct gas costs, indirect gas costs and various adjustments. Anticipated direct gas costs total $23,192,881 and are increased by adjustments totaling $2,486,237 (deferred summer costs of $1,254,455, prior period under collection of $1,161,463 and interest of $70,319). Anticipated indirect gas costs total $962,856, consisting of production and storage capacity, working capital, bad debt and overhead charges. The gas costs to be recovered over the 2002-2003 winter period (anticipated direct and indirect costs and adjustments) total $26,641,974 and are divided by projected winter period sales of 37,004,246 therms (based on 2001/2002 winter normalized sales and projected sales growth of 1.7 percent) to arrive at the average cost of gas rate. (Exh. 2 at 5-6).

Northern applied the ratios established in the Company's revenue-neutral rate redesign proceeding, *see* Order No. 23,674 (April 5, 2001), to the average residential COG rate to determine the Commercial/Industrial (C&I) Low Winter Use COG rate of $0.5183 per therm and the C&I High Winter Use COG rate of $0.7677 per therm.

Northern's proposed 2002/2003 Winter COG residential rate of $0.7200 per therm represents an increase of $0.0651 per therm from the average weighted 2001/2002 Winter COG rate of

$0.6549 per therm. (Hearing Transcript of 10/16/02 (10/16/02 Tr.) at page 22 lines 1-7).

The impact of the proposed firm sales COG rate, Local Distribution Adjustment Clause (LDAC) and delivery rates is an increase in the typical residential heating customer's winter gas costs of $74, a 7.6% increase compared to last winter.

2. **Reasons for the Increase**

According to Northern, the increase in the proposed COG rate compared to last winter's rate can be attributed to 1) an increase in the projected natural gas fuel prices; 2) an increase in demand charges; and 3) an increase in the prior period under-collection compared to the 2001/2002 Winter COG prior period under-collection.

3. **Local Distribution Adjustment Clause**

Under Northern's proposal, the surcharges that will be billed from November 1, 2002 through October 31, 2003 under the LDAC are rate case expenses, environmental costs to remediate Manufactured Gas Plant (MGP) sites and costs related to exiting the Wells LNG Peak Shaving Facilities contract. Credits to be passed through the LDAC over that period include a refund of revenues for the difference between temporary rates and permanent rates in Docket No. DG 01-182 and a refund of an over collection recovered through the conservation charge. The surcharge to recover rate case expenses and credit a refund of revenues for the difference between the temporary and permanent rates are estimated to $480,000 and $980,000, respectively, resulting in a net credit of $0.0096 per therm. In addition, as a result of the settlement reached in Northern's *Petition for Rate Increase*, Docket No. DG 01-182, conservation charges that were collected during the temporary rate period for lost revenues that resulted from discontinued Demand Side Management programs would also be refunded through a $0.0003 per therm credit.

In *Northern Utilities, Inc.*, 84 NH PUC 669 (1999), the Commission approved a plan for the recovery of costs related to early termination of the Company's Wells LNG Peak Shaving Facilities contract. The settlement provided for recovery of $401,139 in year four, commencing November 1, 2002. Northern's reconciliation of prior period costs and revenues resulted in an under-recovery which has been added to this year's recovery amount resulting in a surcharge of $0.0108 per therm.

In *Northern Utilities, Inc.* 83 NH PUC 580 (1998), the Commission approved a recovery mechanism for environmental remediation costs (ERC) associated with former manufactured gas plant (MGP) sites. These costs are filed during Northern's winter Cost of Gas proceeding for Commission review and are recovered over a seven year period. Northern filed for recovery of unamortized deferred environmental remediation costs of $1,035,413, incurred from July 1, 2001 through June 30, 2002. The remediation expenses, combined with prior year's expenses approved for recovery and unamortized to date, third party recovery legal expenses of $2,228, and a $206,851 insurance recovery adjustment, result in $830,790 to be recovered from ratepayers. This determined an ERC rate of $0.0112 per therm to be applied for the period of November 1, 2002 through October 31, 2003.

B. OCA

The OCA did not oppose Northern's proposed COG rate and surcharges.

C. Staff

Staff witness Robert J. Wyatt testified as to Staff's position regarding Northern's long range sales forecast and supply portfolio.

Mr. Wyatt stated Staff generally supports the COG filing but expressed concern that Northern's long term supplemental contracts are susceptible to being under-utilized if load growth projections are not realized. (10/16/02 Tr. at 67 lines 2-22). Mr. Wyatt noted that when the weather is warmer than normal, as experienced last winter, supplemental peaking contracts may not be used at all and Northern's customers end up paying only the fixed costs associated with those contracts. Mr. Wyatt also pointed out that Northern's supplemental peaking contracts are such that its peak shaving plants are rarely needed except during colder than normal winters. (10/16/02 Tr. at 69-70 lines 20-13).

Staff recommended that sales forecasts and supply planning not include volumes used by grandfathered transportation customers. Those customers are responsible for their own supply, storage and capacity contracts. Contracts to cover grandfathered customers raise the costs borne by the firm sales and non-grandfathered firm transportation customers. (10/16/02 Tr. at 70-71 lines 18-17).

Mr. Wyatt supported approval of the costs related to a revised Amendment 3 between Northern and its affiliate, Granite State Gas Transmission, Inc. (Granite State), for additional capacity on the Granite State pipeline. The original COG filing include increased capacity on Granite State well beyond Northern's need for the upcoming winter, but following discussions with Staff, the revised filing reduced that capacity to meet only this winter's requirements, resulting in a substantial savings.

III. **COMMISSION ANALYSIS**

After careful review of the record in this docket, we find that Northern's proposed COG rates and surcharges will result in just and reasonable rates pursuant to RSA 378:7. Accordingly, we accept and approve Northern's proposed 2002/2003 Winter COG rate, the proposed Wells Exit Surcharge, Environmental Cost Recovery Surcharge, Rate Expense Surcharge, Conservation Charges Credit and Temporary Rate Refund Credit. Customers are protected by the additional fact that the costs underlying these rates are reconcilable and subject to the Commission's continued investigation. We share Staff's concerns that supplemental peaking supplies and peakshaving plants may be under utilized if projected load growth is not realized, but understand that the sales and supply projections for this winter are reasonable. We agree with Staff that sales projections should not include grandfathered transportation customers and advise Northern not to enter into any contracts on behalf of those customers. We also suggest Northern re-evaluate its long term supplemental supply contracts to determine if those contracts make sense in light of current economic conditions and as to whether savings may be possible through renegotiation of those contracts.

At hearing, the Commission received no objections to Northern's Motion for Protective Order and Confidential Treatment concerning negotiated pricing terms supplied in response to Staff Data Requests. The basis of Northern's motion is that the information is not publicly disclosed, that the information is commercially sensitive, and that release of the information would disadvantage Northern in future negotiations. The applicable provision of the Right-to-Know Law, RSA 91-A:5, IV, exempts from public disclosure certain commercial or financial information that is private and confidential. Applying this provision requires us to balance the asserted private, confidential, commercial or financial interest against the public's interest in disclosure. *See Union Leader Corp. v. N.H. Housing Fin. Auth.*, 142 N.H. 540, 553 (1997). Applying that test, we determine that the potential disadvantage to Northern in future negotiations outweighs the public's interest in disclosure. We therefore grant Northern's motion.

Based upon the foregoing, it is hereby

ORDERED, that Northern's proposed 2002/2003 Winter COG and FPO per therm rates for the period of November 1, 2002 through April 30, 2003 are APPROVED effective for service rendered on or after November 1, 2002 as follows:

	Cost of Gas	Minimum COG	Maximum COG
Residential	$0.7200	$0.5760	$0.8640
C&I, low winter use	$0.5183	$0.4146	$0.6219
C&I, high winter use	$0.7677	$0.6142	$0.9213

FURTHER ORDERED, that Northern may, without further Commission action, adjust the approved COG rates upward or downward monthly based on Northern's calculation of the projected over or under-collection for the period, but the cumulative adjustments shall not exceed twenty percent (20%) of the approved unit cost of gas, the minimum and maximum rates as set above; and it is

FURTHER ORDERED, that Northern shall provide the Commission with its monthly calculation of the projected over or under-calculation, along with the resulting revised COG rates for the subsequent month, not less than five (5) business days prior to the first day of the subsequent month. Northern shall include a revised tariff pages 38 & 39 - Calculation of Cost of Gas Adjustment and revised rate schedules if Northern elects to adjust the COG rates; and it is

FURTHER ORDERED, that the over or under-collection shall accrue interest at the Prime Rate reported in the *Wall Street Journal*. The rate is to be adjusted each quarter using the rate reported on the first date of the month preceding the first month of the quarter; and it is

FURTHER ORDERED, that Northern's proposed 2002/2003 Local Distribution Adjustment Clause (LDAC) per therm rates for the period November 1, 2002 through October 31, 2003, are APPROVED effective for service rendered on or after November 1, 2002 as follows:

	Demand Side Mgmt.	Envir. Remed. Costs	Wells Exit Fee	Refund Temp. Revenue	Rate Case Expense	LDAC
Residential Heating	(\$0.0003)	\$0.0112	\$0.0108	(\$0.0188)	\$0.0092	0.0121
Residential Non-heating	(\$0.0003)	\$0.0112	\$0.0108	(\$0.0188)	\$0.0092	0.0121
Small C&I	(\$0.0003)	\$0.0112	\$0.0108	(\$0.0188)	\$0.0092	0.0121
Medium C&I	(\$0.0003)	\$0.0112	\$0.0108	(\$0.0188)	\$0.0092	0.0121
Large C&I	(\$0.0003)	\$0.0112	\$0.0108	(\$0.0188)	\$0.0092	0.0121

FURTHER ORDERED, that Northern shall file properly annotated tariff pages in compliance with this Order no later than 15 days from the issuance date of this Order, as required by N.H. Admin. Rules, Puc 1603; and it is

FURTHER ORDERED, that Northern's Motion for Protective Order and Confidential Treatment concerning negotiated pricing terms is GRANTED; and it is

FURTHER ORDERED, that the determination as to confidential treatment made herein is subject to the ongoing authority of the Commission, on its own motion or on the motion of Staff, any party or any other member of the public, to reconsider this Order in light of RSA 91-A, should circumstances so warrant.

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

APPENDIX A

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

RHODE ISLAND PUBLIC UTILITIES COMMISSION

In Re: New England Gas Company

R.I.P.U.C. No. 3401

SETTLEMENT AGREEMENT

The New England Gas Company (the "Company") enters into this settlement agreement (the "Settlement Agreement" or "Agreement") with the Division of Public Utilities and Carriers (the "Division") and the Energy Council of Rhode Island ("TEC-RI") (together, the "Settling Parties"), to resolve all issues arising in this docket, R.I.P.U.C. No. 3401. This Settlement Agreement shall succeed the Price Stabilization Plan approved by the Rhode Island Public Utilities Commission (the "Commission") on September 29, 2000, which expires on June 30, 2002.

The Settling Parties are seeking written approval of the Settlement Agreement by the Commission by June 10, 2002, so that the rates established in this Agreement may become effective as of the statutory deadline in the proceeding, which is July 1, 2002. The revenue requirement established by this Agreement reflects $4.099 million of annual net merger-related savings that have been, and are projected to be, achieved by the Company in the period October 1, 2000 through June 30, 2005. Of that total, $2.049 million in annual savings (or 50 percent of the projected annual savings) are credited directly to customers through the base-rate reduction. The Settlement Agreement also commits the Company to a base-rate freeze through June 30, 2005, if the Agreement is approved without modification by the Commission.

Other elements of the Settlement Agreement include an earnings-sharing mechanism, a unified rate structure for all customers in Rhode Island served by the Company, the introduction of a Distribution Adjustment Charge ("DAC"), the continuation of the weather-normalization clause, the conversion to therm billing, and an incentive mechanism to maximize sales to non-firm customers to the benefit of both customers and the Company. The Settlement Agreement also establishes a schedule for the continuation of discussions between the Company and the Division on the development of a comprehensive service-quality measurement and monitoring program (the "Service-Quality Program"), which would be submitted to the Commission no later than September 30, 2002, for review and approval in a separate proceeding.

I. PREAMBLE

A. Introduction

On July 24, 2000, the Division approved a settlement agreement resolving issues arising from the merger of Providence Energy Corporation, Providence Gas Company ("ProvGas"), Valley Gas Company ("Valley Gas"), and Bristol and Warren Gas Company ("Bristol and Warren") into Southern Union Company ("Southern Union"). This proceeding was docketed as Dockets Nos. D-00-2 and D-00-3.

Under the terms of that settlement, the Company was obligated to develop and serve on all settling parties a plan to consolidate the operations and tariffs of ProvGas, Valley Gas and Bristol and Warren (the "Consolidation Plan"). As part of the Consolidation Plan, the Company was required to include estimated savings projected to result from the consolidation, a timeline for integrating the operations, and an estimation of the present value of future synergy savings. The settlement agreement also obligated the Company to incorporate the provisions of the Consolidation Plan into a base-rate case filing to be filed with the Commission no later than December 1, 2001. Other items covered in the settlement included a provision for the sharing of net merger-related savings identified in the Consolidation Plan between customers and the Company, the establishment of a service-quality measurement and monitoring program, and an agreement by Southern Union not to pursue recovery of the acquisition premium or so-called "golden parachute" or merger-related bonus payments paid to former company officers.

Consistent with the terms of the merger settlement, the Company filed a base-rate case with the Commission on November 1, 2001. To identify net merger-related savings that would be subject to the sharing mechanism agreed upon in the merger settlement, the Company's filing established a pre-merger, stand-alone revenue requirement for ProvGas and for Valley Gas/Bristol and Warren. The Company then combined the stand-alone revenue requirements to establish a consolidated revenue requirement for the New England Gas Company, with adjustments to account for pro forma changes occurring through the Rate Year ending June 30, 2003. Among other items, the pro forma adjustments were designed to reduce the consolidated revenue requirement for the New England Gas Company to reflect the customer share of annual, net merger-related savings projected to be achieved by the Company in the period October 1, 2000 through June 30, 2005, as a result of the implementation of the Consolidation Plan. The Company also included a proposal to establish a unified tariff structure reflecting a single set of rates based on the consolidated revenue requirement.

B. Procedural History

On September 1, 2001, the Company submitted to the Division, the Attorney General and TEC-RI, a comprehensive plan for consolidating all facets of the operations of ProvGas, Valley Gas and Bristol and Warren. On November 1, 2001, the Company filed a request for a base-rate increase totaling $7.2 million on a consolidated basis. During the period November 1 through April 30, 2002, the Company responded to approximately 380 data requests issued by the Division and the Commission. On March 6, 2002, the Division filed the direct testimony of David J. Effron, Richard W. LeLash, Bruce R. Oliver and Matthew I. Kahal. On March 22, 2002, the Company submitted rebuttal testimony. On April 19, 2002 the Division submitted its surrebuttal testimony.

C. Parties' Statement

This Settlement Agreement is based on extensive discovery and negotiations among the Settling Parties concerning all issues involved in establishing new base rates for the Company to become effective July 1, 2002. The Settling Parties do not necessarily agree on every issue resolved by the Settlement; however, the Settling Parties agree that the outcome of this Settlement Agreement is just and reasonable.

II. TERMS OF SETTLEMENT

A. Scope

The Settlement Agreement establishes consolidated distribution rates for the Company's residential, commercial and industrial customers in Rhode Island. References in this Settlement Agreement to "customers" refers to all Rhode Island customers located in the service territories of the former ProvGas and Valley Gas/Bristol and Warren, unless otherwise noted.

B. Revenue Requirement

The consolidated base-rate revenue requirement, upon which rates will be set in this proceeding, shall be $124,927,397, exclusive of purchased gas costs, Rhode Island gross receipts tax, any costs recovered through the DAC, and non-base-tariff revenue. The base-revenue requirement includes the following amounts: (1) environmental response costs ($1,310,000); (2) low-income heating assistance funds, including working capital ($1,592,904); (3) low-income weatherization program costs, including working capital ($200,997); and (4) demand-side management program costs, including working capital ($301,496). The consolidated revenue requirement reflects average, annual net merger-related savings of $4.099 million annually, with 50 percent of those savings credited to customers as a reduction to the consolidated revenue requirement. The revenue requirement also reflects the amortization of one-time operations and maintenance costs necessary to achieve the merger-related savings of $4.099 million, which are set forth in Company Exhibit TEC-3. The amortization of these costs will be completed by June 30, 2005, and will not be reflected in the determination of the consolidated revenue requirement subsequent to that date.

C. Rates, Tariffs, and Terms & Conditions for Service

The implementation of this Settlement Agreement will establish a "one state, one rate" tariff structure for Rhode Island gas customers as of July 1, 2002. The "one state, one rate" principle will be applied to all rate classes across the combined service territory. To mitigate the bill impacts on residential (heating and non-heating) and small commercial and industrial ("C&I") customers in the Valley Gas/Bristol & Warren ("Valley") service area, a credit to the DAC will be applied to these customer classes, so that the average residential and small C&I customer will be held harmless in the first year of the rate consolidation (July 1, 2002 through June 30, 2003).

For the period July 1, 2003 through June 30, 2004, the credit to the DAC established for such customers in the Valley service area will be reduced by 50% and will be phased out as of July 1, 2004, in order to accomplish a phase-in of the unified rate structure. Credits to the DAC developed for such customers in the Valley service area will be collected from the same customer classes in the Providence service area, through an adjustment to the DAC in an aggregate amount equal to the credits provided to the customers in the Valley service area. In each year of the phase in, the credit to residential and small C&I customers in the Valley service area will be accomplished while maintaining a rate reduction for residential and small C&I customers in the Providence service area. Appendix A (attached hereto) sets forth the bill impacts as of July 1, 2002, for all customer classes that will result from the implementation of the unified rate structure and the application of the DAC (including the adjustments made to provide a credit to certain customers in the Valley service area, as discussed above). For those customer classes affected by the DAC adjustments discussed above, bill impacts are also provided as of July 1, 2003 and July 1, 2004.

Appendix B(1) (attached hereto) sets forth the rate tariffs that will take effect for billings to all customers for usage on and after July 1, 2002. Appendix B(2) sets forth the currently effective rate tariffs marked to show changes that are necessary to implement the new tariffs as of July 1, 2002. The effect of the rate consolidation will be to have one set of rates, tariffs, terms, and conditions applying to all customers and to terminate all rates, tariffs, terms, and conditions previously in effect for ProvGas and Valley Gas/Bristol and Warren.

D. Base Rate Freeze

1. Rate Freeze Period

If the Settlement Agreement is approved by the Commission without modification, the base rates set forth in Appendix B(1) will be frozen through June 30, 2005 (the "Rate-Freeze Period"), subject only to the exogenous events defined below ("Exogenous Events") and changes in the DAC, as provided by section I, below. If an Exogenous Event occurs during the Rate-Freeze Period, the Company will adjust its base rates through a credit or debit to the DAC, subject to paragraph 2(c), below.

2. Exogenous Events

(a) State Initiated Cost Change: The Company shall adjust its distribution rates (upward or downward) if the occurrence of a "State Initiated Cost Change," as defined below, causes (in the aggregate) a change in the Company's revenue requirement by more than $350,000. For purposes of this Settlement, the term "State Initiated Exogenous Change" shall mean:

(i) the enactment or promulgation of any new or amended state or local tax laws, regulations, or precedents governing income, revenue, sales, franchise, or property taxes or any new or amended state or locally imposed fees (but excluding the effects of annual changes in local property tax rates and re-valuations);

(ii) the elimination of any existing state or local tax or fee obligations; and

(iii) any state legislative or state regulatory mandates that impose new obligations, duties or undertakings, or remove existing obligations, duties, or undertakings that individually decrease or increase the Company's costs.

(b) Federally Initiated Cost Change: The Company shall adjust its base rates (upward or downward) if the occurrence of a "Federally Initiated Cost Change," as defined below, causes (in the aggregate) a change in the consolidated revenue requirement of more than $500,000. For purposes of this Settlement Agreement, the term "Federally Initiated Cost Change" shall mean:

(i) any externally imposed changes in the federal tax rates, laws, regulations, or precedents governing income, revenue, or sales taxes or any changes in federally imposed fees; and

(ii) any federal legislative or federal regulatory mandates that impose new obligations, duties or undertakings, or remove existing obligations, duties, or undertakings that individually decrease or increase the Company's costs.

(c) Procedure for Adjusting Rates for Exogenous Event: If either of the Exogenous Events described above occur during the Rate-Freeze Period, the Company shall file for adjustments no later than August 1 of each year, based on financial results for the 12-month period ending June 30 of each year. If the Company has not made a filing, the Division (or other Settling Parties) has the right to make a filing on its own to open a proceeding if the Division (or other Settling Parties) believe an Exogenous Event has occurred. Any adjustments shall be subject to review by the Commission, and after public hearing and approval by the Commission, shall be implemented for usage on and after November 1 (unless suspended by the Commission) and shall be collected through the DAC.

In any proceeding under this subsection, the Settling Party claiming that there should be a rate modification resulting from the occurrence of an Exogenous Event shall carry the burden of proving the occurrence and the cost impact. The Company will file a certification with the Commission by August 1 of each year during the Rate-Freeze Period, with copies to the Settling Parties, certifying that, to the best of the Company's knowledge and belief, there have been no occurrences of Exogenous Events, except as identified in the certification.

(d) Earnings Limit For Exogenous Events

If and when the Company makes a filing seeking an adjustment that increases rates under this section, if the average return on equity, calculated using the same methodology as set forth in section F below, for the time period from July 1, 2002 to the end of the last quarter prior to the date of the filing for such adjustment, exceeds 11.25%, the Company will not be permitted to make a rate adjustment until the average return has dropped below 11.25%. If and when the average return drops below 11.25%, the Company may only recover costs on a prospective basis.

E. Cost of Service Ratemaking After the Rate Freeze Period

After the Rate-Freeze Period, no special adjustments to distribution rates for Exogenous Events, as described in the prior section, shall be permitted. The Company may file a base-rate proposal to change distribution rates for usage on or after July 1, 2005. The Parties also have the right to file a complaint with the Commission requesting a cost-of-service review to lower distribution rates on or after July 1, 2005. In any base-rate proceeding, whether commenced by a filing of the Company, a complaint, or on the Commission's initiative, the Company may include an allowance for its share of savings, to the extent permitted by section G of this Settlement.

F. **Incentive-Based Earnings Sharing Mechanism**

The Settling Parties agree that a properly structured incentive-based rate plan can align the interests of the Company and its customers by establishing appropriate incentives to maximize merger-related savings for the benefit of the Company and its customers. To that end, the Settling Parties agree that the Company will implement an earnings-sharing mechanism ("ESM") to provide for the sharing of net merger-related savings, or other savings, that may be achieved in excess of those identified and incorporated into the consolidated revenue requirement. The ESM will remain in place for the period July 1, 2002 through June 30, 2010. Any amounts due to customers as a result of the application of the ESM will be credited to customers through the DAC.

1. <u>Earnings Sharing Calculation</u>

The Company will file the earnings-sharing calculation by September 1 of each year, based on financial results for the 12-month period ending each June 30. For the purpose of such earnings reports, the determination of earnings subject to the ESM will be based on an benchmark return on equity of 11.25 percent, excluding the Company's portion of non-firm margins addressed in section H, below. Results will be adjusted to reflect established Commission ratemaking principles, including the impact of the Weather Normalization Clause, discussed in section J, below. However, there will be no adjustment to actual results to recognize or annualize known and measurable changes.

The return on common equity will be calculated by dividing the net income available for common equity by the common equity applicable to rate base; where the net income available for common equity is equal to operating income adjusted to reflect Commission ratemaking principles less applicable interest and preferred dividends (if any), subject to the limitations in paragraph 2, below. The applicable interest shall be calculated by multiplying average rate base by the percentage debt in the capital structure times the applicable cost rate, and the applicable preferred dividends shall be calculated by multiplying average rate base by the percentage of preferred stock in the capital structure times the applicable cost rate.

The common equity applicable to rate base shall be calculated by multiplying the actual common equity ratio, subject to the limitations in paragraph 2 below, by rate base. The rate base used in these calculations will be the average rate base for the relevant period, based on a five-quarter average and established Commission ratemaking principles. The working capital allowance will be calculated pursuant to the method approved by the Commission in Docket No. 2286. Construction work in progress will be included in rate base, and the allowance for funds used during construction will be included in operating income. No prepaid taxes will be included in rate base. The deferred debits in rate base as of July 1, 2002 will be $3,060,000, representing the remaining balance of deferred Year 2000 costs, exclusive of the legacy customer information system costs, as of that date. These deferred Year 2000 costs, exclusive of the legacy customer information system costs, will continue to be amortized at a rate of $240,000 per year.

2. <u>Capital Structure</u>

Because the Company's actual equity as shown for financial accounting purposes cannot be distinguished from that of Southern Union Company ("Southern Union") as a result of the merger, the Company will use an imputed capital structure for the purpose of calculating the earned return on equity subject to the ESM. The imputed capital structure will be as follows during the Rate-Freeze Period:

Short Term Debt	8.8%
Long Term Debt	45.7%
Preferred Stock	1.9%
Common Equity	43.6%

To calculate the earned return on equity subject to the ESM during the Rate-Freeze Period, the cost of long-term debt will be 7.81%, the cost of preferred stock will be 9.93%, and the short-term debt cost rate will be the most recent 12-month average cost of short-term debt for Southern Union. To calculate the earned return on equity subject to the ESM subsequent to the Rate-Freeze Period, the Company will use the actual cost of long-term debt and the most recent 12-month average cost of short-term debt for Southern Union. All Settling Parties reserve their rights to take a different position regarding the appropriate capital structure and cost rates in any future ratemaking proceeding. If the capital structure and cost rates are changed in any future ratemaking proceeding, the revised capital structure and cost rates will be used for the purpose of calculating the earned return on equity subject to the ESM prospectively.

3. Merger Savings in Operating Expenses

For purposes of determining the level of earnings subject to sharing under this Settlement Agreement, the Company will include $2.049 million in operating expenses during the rate freeze period, which will represent the investors' share of annual net merger-related savings. The Company will continue to include $2.049 million in operating expenses for purposes of determining the level of earnings subject to sharing, until the first base-rate proceeding after the rate-freeze period, in order to represent the investors' share of annual net merger-related savings.

4. Merger Related Costs in Rate Freeze Period

The Rhode Island share of costs incurred to achieve merger savings, which is defined as actual employee severance costs and other one-time operation and maintenance costs, as included on Company Exhibit TEC-3, plus actual Integration/Rate Design costs as included on Company Exhibit WP-SP-1, Schedule 6-C, will be deferred and fully amortized over the period ending June 30, 2005.

5. Sharing Formula

For the purpose of calculating the earnings subject to the ESM, the benchmark return on equity will be 11.25%. Any annual earnings over 11.25%, up to and including 100 basis points, shall be shared 50% to customers and 50% to the Company. Any earnings in excess of 12.25% shall be shared 75% to customers and 25% to the Company. In calculating the earnings subject to the ESM on an annual basis, the benchmark will remain at 11.25%, unless modified in a subsequent proceeding setting base rates to be effective on or after July 1, 2005. The customer share of any excess earnings will be passed through as a credit to the DAC. An example of the sharing of any earnings in excess of 11.25% is shown on Appendix C (attached hereto).

G. Merger Savings After the Rate-Freeze Period

As stated above, the Settling Parties agree the sharing of merger-related savings is an appropriate mechanism to align the interests of the Company and its customers. In addition, the Settling Parties recognize that, once achieved, the Company should have the opportunity to retain its share of merger-related savings for a reasonable time period. To that end, the Settling Parties agree that demonstrable cost savings achieved by the Company shall be shared between the Company and its customers as described in this section.

1. Demonstration of Achieved Cost Savings

Achieved savings shall be measured by subtracting the Measurement-Year Cost of Service ("Measurement-Year COS") from the Adjusted Benchmark Cost of Service ("Adjusted Benchmark COS"). For the purpose of this section, the "Measurement-Year COS" shall be the adjusted base-rate revenue requirement excluding environmental response costs, low-income heating assistance funds, low-income weatherization program costs, and demand-side management program costs in the test-year period used in any base-rate proceeding occurring subsequent to the Rate-Freeze Period, for rates to be effective prior to July 1, 2010. For the purpose of this section, the "Benchmark COS" shall mean the consolidated distribution cost-of-service established in this Settlement Agreement, excluding the customer share of annual net merger savings, environmental response costs, low-income heating assistance funds, low-income weatherization program costs, and demand-side management program costs, or $127,700,000, escalated by 50 percent of the change in GDPIPD from the year ended June 30, 2003 through the Measurement Year. The escalated Benchmark COS will be added to the product of the escalated Benchmark COS times 30 percent of the growth in weather-normalized firm throughput for the period ended June 30, 2003 through the Measurement Year to determine the Adjusted Benchmark COS. For the purpose of this calculation, the year ending June 30, 2003 weather-normalized firm throughput is 345,400,000 therms.

2. Sharing of Merger Savings

The Measurement-Year COS will be used to determine the amount of savings that have been achieved by the Company since the merger (October 1, 2000). Fifty percent (50%) of the savings calculated in paragraph G.1, above, will be escalated by 50 percent of the cumulative change in GDPIPD from the 12 months ended June 30, 2005, and will be allowed as an expense in base-rate filings made to effect a change in rates on or after July 1, 2005. In addition, such savings will be included for purposes of determining the earnings subject to the ESM in all years after the Rate-Freeze Period until July 1, 2010. An example of the quantification of the shared merger savings to be included in the revenue requirement is shown on Appendix D (attached hereto).

In no event will the shared merger savings to be included in the revenue requirement be greater that $2,049,000 plus the Company's share of retained excess earnings above 11.25%, on a pre-tax basis, for the last fiscal year prior to the time of the base-rate filing. An example of the quantification of the cap on the shared merger savings to be included in the revenue requirement is shown on Appendix E (attached hereto).

3. Burden of Proof

For purposes of this subsection, the Company must meet the same burden of evidentiary proof as occurs in a cost-of-service rate case, subject to the review of the Commission and permitted evidentiary challenges by the Division and other intervenors.

H. Non-Firm Margins

The Settling Parties agree that it is appropriate to establish an incentive mechanism that will encourage the Company to promote the development of non-firm margins, which reduce the cost of service to all customers. Accordingly, the treatment of non-firm margins during the Rate-Freeze Period will be as follows:

1. Non-firm margins of $1.6 million are incorporated into the consolidated revenue requirement. To the extent that non-firm margins for the 12-month period ending June 30 of each year are less than $1.6 million, the Company will recover amounts up to this

threshold amount through the DAC. To the extent that non-firm margins for the 12-month period ending June 30 are greater than $1.6 million, customers will receive a credit for 75 percent of the margins in excess of the threshold through the DAC, as described in section I, below.

2. Seventy-five percent (75%) of all non-firm margins will represent the customers' portion of non-firm margins. Twenty-five (25%) of all non-firm margins will represent the Company's portion of non-firm margins. Such margin will accrue to the Company and shall be excluded from the calculation of the Earnings Sharing Mechanism under sections F and G of this Settlement Agreement.

I. **Distribution Adjustment Clause**

The Settling Parties agree that the Company will establish a reconciling Distribution Adjustment Charge (referenced above as "DAC") to collect or refund certain costs not collected through base rates that are applicable to sales and transportation customers. To the extent that costs associated with, low income assistance programs, low-income weatherization, demand side management program, or environmental response differ from the amounts of such costs specified in Paragraph B, such difference will be reflected as a charge or credit to the DAC. In addition, system balancing costs will be reconciled through the DAC, and adjustments for margins from non-firm sales and transportation, earnings sharing, weather normalization and service-quality will take place through the DAC. Each year on August 1st, the Company will file a proposed DAC based on forecasts of applicable costs and volumes and will incorporate the results of a reconciliation for the 12-month period ending the previous June 30. The DAC approved by the Commission will become effective on November 1 of each year.

J. Weather Normalization Clause

The Settling Parties agree that a weather normalization clause is an appropriate mechanism to mitigate the impact of weather volatility on customer billings. To that end, the Settling Parties agree that the Company shall compare actual heating degree days ("DD") to normal heating degree days at the end of each peak season (November through April). For each DD greater than 4,874 (two percent colder than normal), customers shall accrue an amount equal to $9,000 per DD. For each DD less than 4,682 (two percent warmer than normal), the Company shall accrue an amount equal to $9,000 per DD. Recovery of the total amounts owed shall be recovered by the Company, or credited to customers, through the DAC, discussed in section I, above.

K. Conversion to Therm Billing

The Settling Parties agree that therm billing is a more appropriate approach to customer billing since it better recognizes the heat content of each unit of natural gas. Rates will be revised to reflect therm billing without a resulting dollar impact on customer bills. The Company will institute therm billing using a seasonal conversion factor.

L. Accounting Treatment for Environmental Response Cost

The Settling Parties agree that the Company shall be entitled to recover Environmental Response Costs, as defined below.

(a) <u>Definition of Environmental Response Costs</u>: Environmental Response Costs are all reasonably and prudently incurred costs associated with evaluation, remedial and clean-up obligations of the Company arising out of the Company's utility-related ownership and/or operation of, including, but not limited to: (1) manufactured gas plants and sites associated with the operation and disposal activities from such gas plants; (2) mercury regulators; and (3) meter disposal. In addition to actual remedial and clean up costs, "Environmental Response Costs" also includes, but is not limited to the cost of acquiring property associated with the clean up of such sites as well as litigation costs, claims, judgments, and settlements associated with such sites.

(b) Recovery of Environmental Response Costs

(1) The Company will use best efforts to minimize the Environmental Response Costs ("ERC") consistent with applicable regulatory requirements and sound environmental policies and to minimize litigation costs that may arise therefrom. In the event that the Company incurs such costs during the fiscal-year period ending June 30, the Company will be entitled to recover the costs through the DAC. The Company will amortize those costs over a 10-year period. Thus, the total amount of ERC to be recovered from customers during the 12-month period of November 1 through October 31 of each year (which is the period in which the DAC is applied), will equal one-tenth of the actual ERC incurred by the Company during the prior 12-month period ending June 30. In addition, any applicable insurance proceeds net of costs associated with obtaining such proceeds shall be credited to customers through the DAC.

(2) In order to limit the bill impacts that could potentially result from the incurrence of environmental remediation costs, the ERC factor contained in the DAC shall be limited to an increase of no more than $0.01 per therm in any annual DAC filing. If this limitation results in the Company recovering less than the amount that would otherwise be eligible for recovery in a particular year, then beginning on the date that the proposed ERC factor becomes effective, carrying costs shall accrue to the Company on the portion of the environmental remediation costs not included in the ERC factor as a result of this limitation. Such carrying costs shall accrue through the year in which such amount, together with accumulated carrying costs, are recovered from ratepayers. Any amounts so deferred shall be incorporated into the ERC factor in succeeding years consistent with the $0.01 per therm ERC factor annual increase limitation. Such carrying charges shall accrue at the Interest on Deferred Balance rate specified in Section 1 schedule C of the Company's General Rules and Regulations.

M. Service Quality Program

The Settling Parties agree that the quality of service experienced by customers is an important factor in consolidating the operations of the New England Gas Company. The Company and the Division will continue ongoing discussions regarding the development and implementation of a Service-Quality Program, with the intention of submitting a proposal to the Commission no later than September 30, 2002, for review and approval in a separate proceeding. If the Company and the Division cannot agree on a Service Quality Plan, the

Company will file its own proposal by September 30, 2002. Any Service Quality Plan filed with the Commission will include a system of penalties and penalty offsets. In addition, the Company's ability to participate in the ESM will be linked to the establishment of the Service Quality Plan.

N. ACCOUNT-RESTORATION AND RETURN CHECK CHARGES

The Settling Parties agree that the Company shall waive account-restoration charges and return check fees for customers eligible for low-income assistance programs.

O. JOINT AND COMMON COST ALLOCATIONS

The Settling Parties agree that a portion of Southern Union's joint and common costs may be allocated to the Company and may be requested for recovery in the cost of service in future base-rate proceedings. Such costs will be allocated to the Company on terms that are no less favorable than those terms applied in other jurisdictions wherein Southern Union operates. The Settling Parties agree that, in any base-rate proceeding, the Company will have the burden of proving the reasonableness of any allocated or assigned cost to the Company from any affiliate, division or subsidiary of Southern Union, including all cost allocations. The Settling Parties further agree that the Commission has the authority to assess the reasonableness of such costs and the allocation thereof as part of its determination of the revenue requirement in that proceeding.

III. EFFECT OF SETTLEMENT AGREEMENT

This Settlement Agreement is the result of negotiations among the Settling Parties. The discussions that have produced this Agreement have been conducted on the explicit understanding that all offers of settlement and discussions relating hereto are and shall be privileged, shall be without prejudice to the position of any party or participant presenting such offer or participating in any such discussion, and are not to be used in any manner in connection with these or other proceedings involving any one or more of the parties to this Settlement or otherwise. The agreement by a party to the terms of this Settlement Agreement shall not be construed as an agreement as to any matter of fact or law for any other purpose. In the event that the Commission (i) rejects this Agreement, (ii) fails to accept this Agreement as filed, or (iii) accepts this Agreement subject to conditions unacceptable to any party hereto, then this Agreement shall be deemed withdrawn and shall be null and void in all respects.

indicate a difference of ten percent over or under the amount the Department has authorized to be collected during the period, the Company may make an interim filing during the effective period revising the Conservation Charge either up or down for the remainder of the period with the approval of the Department. An amended Conservation Charge must be submitted 10 days before the first billing cycle of the month in which it is to take effect.

7.04 Environmental Response Costs Allowable for LDAC

7.04.01 Purpose

The purpose of this provision is to establish a procedure that allows Bay State subject to the jurisdiction of the Department to adjust, on an annual basis, its rates for the recovery from its firm sales and firm transportation customers environmental response costs associated with manufactured gas plants.

7.04.02 Applicability

A Remediation Adjustment Cost ("RAC") charge shall be applied to firm sales and firm transportation throughput of the Company subject to the jurisdiction of the Department as determined in accordance with the provisions of Section 7.04 of this clause. Such RAC shall be determined annually by the Company as defined below, subject to review and approval by the Department as provided for in this clause.

7.04.03 Environmental Cost Allowable

All environmental response costs associated with manufactured gas plants, adjusted for deferred tax benefits, and one half of the expenses incurred by the Company in pursuing insurance and third party claims, less one-half of any recoveries received by the Company as a result of such claims may be included in the LDAC.

The total annual charge to the Company's ratepayers for Environmental Response Costs during any Remediation Cost Recovery Year shall not exceed five percent (5%) of the Company's total revenues from firm gas sales during the preceding calendar year. If this limitation results in the Company recovering less than the amount that would otherwise be recovered in a

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particular Remediation Cost Recovery Year, then beginning with the date upon which the annual charge would have been effective, carrying costs shall accrue to the Company upon the unrecovered portion of the Remediation costs that otherwise would have been allowable. Carrying costs shall accrue through the Remediation Cost Recovery Year in which such amount, together with any accumulated carrying costs, is actually recovered by the Company from its ratepayers and shall accrue at the pre-tax weighted cost of capital rate as defined in Section 7.04.05.

7.04.04 Effective Date

Forty-five ("45") days prior to the beginning of the billing month of May of each year, the Company will file with the Department for its consideration and approval, the Company's request for a change in the RAC applicable to all firm sales and firm transportation throughput for the subsequent twelve month period commencing with the billing month of May.

7.04.05 Definitions

(1) Deferred Tax Benefit shall be the unamortized portion of actual environmental response costs multiplied by the Company's effective statutory federal and state income tax rate, and by the Company's tax adjusted cost of capital as approved in its last rate proceeding.

(2) Environmental Response Costs shall include all costs of investigation, testing, remediation, litigation expenses, and other liabilities relating to manufactured gas plant sites, disposal sites, or other sites onto which material may have migrated, as a result of the operating or decommissioning of Massachusetts gas manufacturing facilities.

(3) Expenses and Recoveries Associated with Insurance and Third-Party Expenses and Recoveries shall include one-half the expenses incurred by the Company in pursuing insurance and third-party claims and one-half of any recoveries or other benefits received by the Company as a result of such claims.

(4) Pre-tax Weighted Cost of Capital is the result of the calculation of the weighted cost of capital minus the weighted cost of debt, divided by one minus the combined tax rate, plus the weighted cost of debt.

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7.04.06 Reconciliation Adjustments

Calculation of the RAC

The RAC consists of one-seventh of the actual response costs incurred by the Company in a calendar year for each year until fully amortized, less a deferred tax benefit, plus one-half of insurance and third-party expenses for the calendar year, less one-half of insurance and third-party recoveries for the calendar year, plus the prior year's RAC reconciliation adjustment. This amount is then divided by the Company's forecast of total firm sales volumes and firm transportation throughput for the upcoming year.

The deferred tax benefit is calculated by multiplying the unamortized environmental response costs by the combined tax rate as defined in Section 7.04.5, and by the Company's pre-tax weighted cost of capital as defined in Section 7.04.5.

7.04.07 Remediation Adjustment Cost (RAC) Factor Formula

$$RAC = \frac{\text{sum}\left(\frac{ERC}{7}\right) - DTB + ((IE - IR) \times .5) + Rrac}{A : TP\ vol}$$

and:

$$DTB = UERC \times TR \times \left(\frac{(WCC - WCD)}{(1 - TR)} + WCD \right)$$

Where:

A:TPool	Forecast Annual throughput Volumes inclusive of all firm sales and firm transportation throughput.
DL	Number of Days Lag from the purchase of gas from suppliers to the payment by customers
DTB	Deferred Tax Benefit as defined in Section 7.04.05.

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ERC	Environmental Response Costs as defined in Section 7.04.05.
IE	Expenses associated with pursuing Insurance and third-party claims as defined in Section 7.04.
IR	Insurance and third-party Recoveries as defined in Section 7.04.
RAC	Remediation Adjustment Factor as defined in Section 7.04.08
Rrac	Remediation Adjustment Clause Reconciliation Adjustment - Account 176.6 balance as outlined in Section 7.04.08.
TR	Combined Tax Rate
UERC	Unamortized Environmental Response Costs
WCC	Weighted Cost of Capital
WCD	Weighted Cost of Debt

7.04.08 Remediation Adjustment Cost (RAC) Factor Calculation

(1) The following definitions pertain to the Remediation Adjustment Clause (RAC) reconciliation adjustment calculations:

(a) Remediation Adjustment Cost Expenses Allowable Per Formula shall be:

i. One seventh of each calendar year's environmental response costs (ERC) as defined in Section 7.04.03, less the deferred tax benefit as defined in Section 7.04.05.

ii. One-half of insurance and third-party expenses (IE), less one-half of insurance and third-party recoveries (IR).

(b) RAC (Remediation Adjustment Cost) portion of the LDAF as computed in Section 7.04.07 is used as the convention for recognizing revenues toward Environmental Response Costs.

(2) Calculation of the Reconciliation Adjustment 176.6
Account 176.6 shall contain the accumulated difference between revenues toward environmental response costs as calculated by multiplying the RAC times monthly firm sales volumes and transportation throughput and environmental response costs allowable per formula.

7.04.09 Application of RAC to Bills

The RAC ($ per therm) shall be calculated to the nearest one one-hundredth of a cent per therm and will be applied to the monthly firm sales and firm

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transportation throughput.

7.04.10 Information to be Filed with the Department

The annual RAC filing will include copies of all bills and receipts relating to any environmental response costs and expenses related to insurance and third-party recoveries incurred in the preceding calendar year as well as a schedule depicting the particular purpose of the amount of any environmental response costs and expenses related to insurance and third party recoveries incurred in the preceding calendar year.

7.05 FERC Order 636 Transition Costs Allowable for LDAC

7.05.01 Purpose

The purpose of this provision is to establish a procedure that allows Bay State subject to the jurisdiction of the Department to adjust, on an annual basis, its rates for the recovery from its firm sales and transportation customers FERC Order 636 Transition Costs.

7.05.02 Applicability

The FERC Order 636 Transition Cost charge (TC) shall be applied to all firm sales and firm transportation throughput of the Company subject to the jurisdiction of the Department as determined in accordance with the provisions of Section 7.05 of this clause. Such TC shall be determined annually by the Company as defined below, subject to review and approval by the Department as provided for in this clause.

7.05.03 Transition Cost Allowable for LDAC

All costs as defined and approved by the FERC, including: (1) gas supply realignment or GSR costs; (2) stranded costs; and (3) new facilities costs.

7.05.04 Effective Date of Transition Cost Charge

FILED
OFFICE OF THE SECRETARY
01 FEB 20 AM 11: 33
FEDERAL ENERGY
REGULATORY COMMISSION

Missouri Public Service Commission

POST OFFICE BOX 360
JEFFERSON CITY, MISSOURI 65102
573-751-3234
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http://www.psc.state.mo.us

February 16, 2001

ORIGINAL

Mr. David Boergers, Secretary
Office of the Secretary
Federal Energy Regulatory Commission
888 First Street, N.E., Room 1-A
Washington, D.C. 20426

RE: Docket No. RP93-109

Dear Mr. Boergers:

Enclosed for filing in the above-captioned case are an original and fifteen (15) conformed copies of the **COMMENTS OF THE MISSOURI PUBLIC SERVICE COMMISSION IN SUPPORT OF STIPULATION AND AGREEMENT.**

Please date and time stamp the extra copy which is enclosed and return it to me in the enclosed self-addressed envelope.

Thank you for your attention to this matter.

Sincerely yours,

Lera L. Shemwell by TFS

Lera L. Shemwell
Associate General Counsel
(573) 751-7431
(573) 751-9285 (Fax)

LLS:sw
Enclosures
cc: Counsel of Record

FERC DOCKETED
FEB 20 2001

010221-0418-2

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Williams Natural Gas Company) Docket No. RP93-109

COMMENTS OF THE
MISSOURI PUBLIC SERVICE COMMISSION
IN SUPPORT OF STIPULATION AND AGREEMENT

Pursuant to Rule 602(f) of the Federal Energy Regulatory Commission's ("Commission") Rules of Practice and Procedure, 18 C.F.R. §385.602(f), the Missouri Public Service Commission ("MoPSC") hereby *submits its comments in support of the Stipulation* and Agreement of Settlement ("Stipulation") filed on January 31, 2001 in the above captioned proceeding.

The MoPSC is a "state commission" within the meaning of Section 1.101a(k) of the Commission's general regulations. The MoPSC has actively participated in this proceeding to protect the interests of Missouri's natural gas consumers who receive service from Williams Gas Pipelines Central, Inc., formerly known as Williams Natural Gas Company (Williams).

This Stipulation is the result of extensive negotiations between the parties in this case. If the Commission approves this Stipulation, it will settle the issue of Williams' recovery of its environmental clean-up costs. The Stipulation establishes an annual environmental cost of service allowance of $1,700,000 for the rates associated with this docket's locked-in period. This means that Williams is due an additional $1,012,150, which will be offset against the $2,808,519 refund Williams owes customers for environmental cost recoveries from third-party insurers during calendar year 2000.

Since Williams refunded the balance of the environmental cost recovery moneys on January 31, 2001, the Stipulation is considered to be consistent with the public interest and to be a fair and reasonable resolution of the remanded environmental cost issue in this docket.

WHEREFORE, for the foregoing reasons, the MoPSC respectfully requests the January 31 Stipulation and Agreement be certified by Presiding Administrative Law Judge Harfeld and approved by the Commission.

Respectfully submitted,

DANA K. JOYCE
General Counsel

Lera L. Shemwell MRS

Lera L. Shemwell
Associate General Counsel

Missouri Public Service Commission
P. O. Box 360
Jefferson City, MO 65102
(573) 751-7431 (Telephone)
(573) 751-9285 (Fax)
lshemwel@mail.state.mo.us

CERTIFICATE OF SERVICE

Pursuant to Rule 2010 of the Commission's Rules of Practice and Procedure, I hereby certify that I have this day served a copy of the foregoing document on all persons designated on the official service list compiled by the Secretary in this proceeding,

Dated at Jefferson City, Missouri this 16th day of February, 2001.

Lera L. Shemwell MRS

Lera L. Shemwell

GARY W. BOYLE
Senior Counsel – Gas Pipeline Central
918/573-2359
918/573-4195 office fax
gary.boyle@williams.com

ORIGINAL

01 JAN 31 PM 3:29

Williams

Gas Pipelines - Central
One Williams Center
P.O. Box 3288
Tulsa, Oklahoma 74101
918/588-2000

January 31, 2001

David P. Boergers
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

RE: Williams Natural Gas Co., Docket No. RP93-109 - 000

Dear Mr. Boergers:

Pursuant to Rule 602 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission (Commission), 18 C.F.R. § 385.602, Williams Gas Pipelines Central, Inc., formerly named Williams Natural Gas Company (Williams), hereby submits an original and fourteen (14) copies of a Stipulation and Agreement (Agreement) in the captioned proceeding.

In addition, this transmittal letter, including the explanatory statement, constitute compliance with Rule 602(c)(1)(ii). A proposed order of the Commission accepting the Agreement is also attached.

A. EXPLANATORY STATEMENT

On April 30, 1993, Williams filed a general Section 4 rate filing proposing, among other things, to amortize over a three-year period actual past period environmental costs of $4.2 million. On November 22, 1995, the Presiding ALJ issued an Initial Decision approving the three-year amortization of environmental costs with a procedure for refunding amounts that Williams recovered from third parties. On December 19, 1996, the Commission affirmed in part and reversed in part the ALJ's Initial Decision rejecting Williams' proposed amortization in favor of the "test period" method and ruling that $1.4 million was a reasonable representation of the level of environmental costs to be recovered in rates. Williams appealed that decision to the D. C. Circuit Court of Appeals. The D.C. Circuit Court of Appeals remanded the environmental cost issue to the Commission finding that it had not adequately explained why it had approved a $1.4 million annual environmental allowance. The active parties have engaged in discovery, Williams has filed direct testimony and all parties have spent time discussing settlement. This Stipulation and Agreement represents a final, comprehensive resolution of environmental costs in this proceeding. Williams believes this settlement is supported by all active parties.

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B. PROCEDURES AND COMMENTS

Williams respectfully requests that the instant Agreement be transmitted forthwith to Presiding Administrative Law Judge Harfeld pursuant to Rule 602(b)(2)(i) of the Commission's Rules. Pursuant to Rule 602(f)(2), initial comments on this Agreement must be filed on or before February 20, 2001, and reply comments must be filed on or before March 2, 2001. *Failure to file comments will be deemed a waiver of the right to file comments on the offer of settlement.*

C. WAIVERS

Williams respectfully requests waiver of any provisions of the Commission's regulations and any other waivers which may be necessary for approval of the Agreement as proposed herein.

D. SERVICE

The Agreement, together with all attachments thereto, is this day being served pursuant to Rule 602(d)(1) upon all participants listed on the official restricted service list in this proceeding on file with the Secretary of the Commission.

Sincerely,

Gary W. Boyle /TLW

Gary W. Boyle
Senior Counsel

Williams Gas Pipelines Central
RP93-109 Environmental Cost
Settlement Allocation

Appendix A

Shipper		12-Mos. Ending Sep 30, 2000 Revenue 1/	Percentage		Allocated Settlement Amount
Acme Brick	$	79,109	0.0555%	$	841
AFG Industries	$	102,873	0.0722%	$	1,094
AG Processing	$	31,823	0.0223%	$	338
Altamont	$	40,371	0.0283%	$	429
Americus Gas	$	29,774	0.0209%	$	317
Amoco Energy	$	527,106	0.3698%	$	5,604
Aquila Energy Marketing	$	1,021	0.0007%	$	11
Aquila Energy Transportaion	$	3,601	0.0025%	$	38
Argonia	$	18,837	0.0132%	$	200
Auburn	$	98,286	0.0690%	$	1,045
Avant	$	10,402	0.0073%	$	111
Bayer	$	42,315	0.0297%	$	450
Billings	$	16,363	0.0115%	$	174
Burlington	$	6,511	0.0046%	$	69
Central Mo State Univ	$	42,701	0.0300%	$	454
Certainteed Co.	$	295,315	0.2072%	$	3,140
City Utilities of Springfield	$	5,284,997	3.7078%	$	56,192
Cleveland	$	108,339	0.0760%	$	1,152
CMS Field	$	163,681	0.1148%	$	1,740
Comm of Land Office	$	10,561	0.0074%	$	112
Conagra Energy	$	36,931	0.0259%	$	393
Copan	$	31,927	0.0224%	$	339
Cotton Valley	$	15,000	0.0105%	$	159
Denison	$	8,911	0.0063%	$	95
Duke Energy	$	2,640,836	1.8527%	$	28,078
Dynegy Mkt & Trade	$	2,014	0.0014%	$	21
Eckert Gas	$	2,324	0.0016%	$	25
Empire Dist. Electric	$	2,175,232	1.5261%	$	23,128
Energy One	$	154,251	0.1082%	$	1,640
Enserco Energy	$	102,200	0.0717%	$	1,087
Excel Corp.	$	35,066	0.0246%	$	373
Fag Bearing	$	10,630	0.0075%	$	113
Farmland Industries	$	1,150,669	0.8073%	$	12,234
Flint Hills	$	2,008	0.0014%	$	21
Ford	$	11,756	0.0082%	$	125
Freedom	$	11,876	0.0083%	$	126
Gate	$	4,297	0.0030%	$	46
General Motors	$	450,920	0.3164%	$	4,794
Granby	$	51,582	0.0362%	$	549
Greeley Gas Co.	$	1,545,712	1.0844%	$	16,435
Greeley Gas Co.	$	6,301,238	4.4207%	$	66,997
Grove Municipal	$	570,320	0.4001%	$	6,064

Williams Gas Pipelines Central
RP93-109 Environmental Cost
Settlement Allocation

Appendix A

Shipper	12-Mos. Ending Sep 30. 2000 Revenue 1/	Percentage	Allocated Settlement Amount
GS-WRI	$ 190,596	0.1337%	$ 2,027
Hamilton	$ 9,400	0.0066%	$ 100
Heartland Cemt	$ 25,983	0.0182%	$ 276
Howard	$ 17,429	0.0122%	$ 185
International Paper	$ 11,981	0.0084%	$ 127
Iola	$ 328,796	0.2307%	$ 3,496
Jane Phillips Med. Center	$ 6,956	0.0049%	$ 74
Kansas City Power & Light	$ 18,215	0.0128%	$ 194
Kansas City Power & Light	$ 971,513	0.6816%	$ 10,330
Kansas Gas Service	$ 42,628,863	29.9070%	$ 453,246
KMGA	$ 1,143,678	0.8024%	$ 12,160
Laclede	$ 2,982,346	2.0923%	$ 31,710
Lawrence Paper	$ 29,284	0.0205%	$ 311
Leann Gas	$ 174,868	0.1227%	$ 1,859
Lebo	$ 20,433	0.0143%	$ 217
Liberal	$ 18,902	0.0133%	$ 201
Manchester Pipeline Corp.	$ 3,795	0.0027%	$ 40
Mannford	$ 108,953	0.0764%	$ 1,158
Margasco Partnership	$ 102,422	0.0719%	$ 1,089
Marshall Municpal Utilities	$ 5,480	0.0038%	$ 58
Mclouth	$ 15,326	0.0108%	$ 163
Midwest United	$ 76,193	0.0535%	$ 810
Missouri Gas Energy	$ 49,677,487	34.8521%	$ 528,190
Mountain Energy	$ 603,446	0.4234%	$ 6,416
Mulberry	$ 18,740	0.0131%	$ 199
Nebraska Public Gas Agency	$ 451,419	0.3167%	$ 4,800
Nelagoney Rural	$ 1,650	0.0012%	$ 18
Neodesha	$ 99,685	0.0699%	$ 1,060
Oneok Energy	$ 2,018,616	1.4162%	$ 21,463
Orlando	$ 5,159	0.0036%	$ 55
Oronogo	$ 4,734	0.0033%	$ 50
Ozark Natural	$ 263,958	0.1852%	$ 2,807
PG&E Energy Services	$ 78,408	0.0550%	$ 834
Pittsburg Corning	$ 98,467	0.0691%	$ 1,047
Plattsburg	$ 119,481	0.0838%	$ 1,270
Public Srv Co	$ 16,287	0.0114%	$ 173
Questar ETC	$ 346,703	0.2432%	$ 3,686
Reading	$ 4,489	0.0031%	$ 48
Reliant	$ 4,216	0.0030%	$ 45
Reliant	$ 98,749	0.0693%	$ 1,050
Severy Gas	$ 11,622	0.0082%	$ 124
Southern Mo. Gas	$ 1,052,809	0.7386%	$ 11,194

Williams Gas Pipelines Central
RP93-109 Environmental Cost
Settlement Allocation

Appendix A

Shipper	12-Mos. Ending Sep 30. 2000 Revenue 1/	Percentage	Allocated Settlement Amount
Talbot Industries	$ 6,363	*0.0045%*	$ 68
Tenaska Mkt	$ 182,996	0.1284%	$ 1,946
Terra Nitro LT	$ 540,000	0.3788%	$ 5,741
TXU Energy	$ 6,358	0.0045%	$ 68
Tyson	$ 137,095	0.0962%	$ 1,458
US Gypsum	$ 196,057	0.1375%	$ 2,085
US Gypsum	$ 34,092	0.0239%	$ 362
Utilicorp Energy	$ 7,981	0.0056%	$ 85
Utilicorp United	$ 7,981,648	5.5997%	$ 84,864
Viola	$ 5,168	0.0036%	$ 55
Vulcan Chemical	$ 336,926	0.2364%	$ 3,582
Wakita	$ 17,044	0.0120%	$ 181
Wann Public Works	$ 3,297	0.0023%	$ 35
WBI Production	$ 554,724	0.3892%	$ 5,898
WES	$ 5,109,095	3.5844%	$ 54,322
Western Resources	$ 984,464	0.6907%	$ 10,467
WFS Company	$ 289,619	0.2032%	$ 3,079
Wheaton Natural Gas	$ 47,770	0.0335%	$ 508
Totals	$ 142,537,940	100.0000%	$ 1,515,517

Net Settlement $ 1,515,517

1/ Includes firm transportation and firm storage reservation revenues for the twelve months ended September 30, 2000.

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

Williams Natural Gas Company) Docket No. RP93-109

**STIPULATION AND AGREEMENT
(January 31, 2001)**

Pursuant to Rule 602 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission (Commission), 18 C.F.R. § 385.602, Williams Gas Pipelines Central, Inc., formerly named Williams Natural Gas Company (Williams), submits this Stipulation and Agreement in settlement of the remaining contested issues in the captioned proceeding.

DESCRIPTION OF PROCEEDING

On April 30, 1993, Williams made a general Section 4 rate filing (Docket No. RP93-109). The Commission suspended the effective date of the proposed rate increase until November 1, 1993, and set the matter for hearing.[1] Evidentiary hearings before an ALJ were conducted in 1994. Initial and reply briefs were filed by various parties. Among the many issues addressed at the hearing was the issue of Williams' recovery of its environmental costs. Williams proposed to amortize over a three-year period actual past period costs of $4.2 million instead of projecting environmental costs under a test period methodology. By amortizing these costs over three years, Williams would have been allowed to recover $1.4 million each year. On November 22, 1995, the Presiding Judge issued an Initial Decision which approved the three-year amortization with a procedure for refunding any amounts Williams recovered from third parties, such as liability insurance carriers or the suppliers of the PCB-laden material.[2] Several parties filed exceptions to the Initial Decision. Williams filed a new Section 4 rate case in 1995,

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1 Williams Natural Gas Co., 63 FERC ¶ 61,241 (1993).

2 Williams Natural Gas Co., 73 FERC ¶ 63,015 (1995).

with the result that the instant rate case covers a locked-in period of November 1, 1993, through July 31, 1995.

On December 19, 1996, the Commission affirmed in part and reversed in part the ALJ's Initial Decision.[3] The Commission rejected Williams' proposed amortization in favor of the "test period" method.[4] The Commission determined that the $1.4 million annual amount that the participants and the ALJ arrived at using an amortization method was a reasonable equivalent of Williams' actual Polychlorinated Biphenyl (PCB) clean-up related test period costs for use as a projection of Williams' future annual PCB costs under the test period methodology.[5]

On rehearing, Williams did not contest the Commission's requirement that it recover these costs based on a test period methodology but it did assert that the Commission erred in adopting an annual allowance of $1.4 million for PCB clean-up costs. The Commission ruled that the $1.4 million was a reasonable representation of the level of these costs to be recovered in rates given the record that had been developed.[6] Williams appealed that decision to the D.C. Circuit Court of Appeals.

The court granted Williams' petition and remanded the PCB issue to the Commission finding that it had not adequately explained why it had approved use of the $1.4 million figure. The court found that an allowance developed under an amortization method is not useful for applying past experience to project future costs as required by the test period method. The court

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3 Williams Natural Gas Co., 77 FERC ¶ 61,277 (1996).

4 18 C.F.R. § 154.303.

5 Williams Natural Gas Co., 77 FERC ¶ 61,277 at 62,181-183 (1996).

6 Id. at 61,679-80.

also found that the Commission had not explained why Williams' $3.9 million "test period actual" figure was inadequate.

On October 13, 2000, the Commission directed the Chief Administrative Law Judge to appoint an Administrative Law Judge to preside over a hearing in this matter and encouraged the parties to reach a settlement. Williams has filed direct supplemental testimony, the Staff and Intervenors have engaged in discovery, and the parties have spent considerable time discussing settlement. This Stipulation and Agreement is a product of those discussions.

This Settlement is supported by all parties active in these proceedings and resolves all outstanding issues in this docket.

SETTLEMENT PROVISIONS

ARTICLE I

Environmental Cost of Service

Williams will be entitled to recover an annual environmental cost of service of $1,700,000 for the locked-in period applicable in this docket. The Commission originally allowed Williams to recover an annual cost of service of $1,355,813 for the locked-in period applicable in this docket. Applying the settlement environmental allowance to the original amount authorized by the Commission for the locked-in period results in a net additional amount due Williams of $1,012,150 including interest at the Commission's established rates through January 31, 2001.

ARTICLE II

Collection

Williams will collect the net cost of service increase of $1,012,150 by set-off against the pass-through of insurance proceeds due on January 31, 2001. During calendar year 2000, Williams collected $2,808,519 from third-party insurers related to its environmental costs, including interest at the Commission's established rates through January 31, 2001. Under the Commission's prior orders in this proceeding, Williams is required to pass through to its customers 90% of any such third-party collections.[7] Williams has therefore allocated to its customers $2,527,667 of its third-party collections. To effect the set-off provided for herein, Williams will refund a total of $1,515,517 to its customers on January 31, 2001.

ARTICLE III

Allocation and Payment

A. Williams will allocate its net pass-through of third-party proceeds to its firm customers based on firm reservation revenues during the twelve months ended September 30, 2000. The allocation, reflected on Appendix A, sets forth the amount to be refunded to each party under the terms of this Settlement.

B. Williams will make the refunds on Appendix A to each of the customers listed thereon on or before January 31, 2001.

C. If the Commission should issue a final and non-appealable order directing Williams to pass-through the net amount due under this Settlement in a manner inconsistent with Appendix A, Williams will have the right to correct each party's net refund by adjusting the amount of any future pass-through of third-party environmental collections, if any.

D. The parties agree that Williams' future pass-through of third-party environmental proceeds, if any, should be allocated to Williams' customers based on firm reservation revenues for the twelve months ended on the September 30 immediately preceding the date on which the

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[7] Williams Natural Gas Co., 77 FERC ¶ 61,277 at 62,182 (1996); Williams Natural Gas Co., 73 FERC ¶ 63,015 at 65,075 (1995).

pass-through payments are made. Any future payments related to third-party environmental proceeds shall continue to be refunded to customers by the 31st of January following the calendar year in which Williams receives the third-party proceeds. Williams will file a refund plan consistent with the allocation set forth in this paragraph no less than 30 days prior to the date on which refunds are required.

ARTICLE IV

Refund Report

This Stipulation and Agreement will serve as Williams' refund report in this proceeding related to its obligation to pass-through a portion of the third-party proceeds it received during calendar year 2000. The Commission's Order approving this Stipulation and Agreement will constitute approval of Williams' refund report and will resolve all remaining issues in this docket.

ARTICLE V

Effective Date

The Commission's order approving this Stipulation and Agreement shall constitute a waiver of the Commission's Rules and Regulations, including 18 C.F.R. Part 154, Subpart C, to the extent necessary to effectuate all of the provisions of this Stipulation and Agreement. This Stipulation and Agreement shall be effective on January 31, 2001, regardless of the date on which the Commission approves this Stipulation and Agreement.

ARTICLE VI

General Reservations

This Settlement Agreement is submitted for Commission approval pursuant to Rule 602 of the Commission's Rules of Practice and Procedure. If it does not become effective for any reason it shall be considered privileged and not admissible in evidence or made a part of the record in any proceeding.

ARTICLE VII

Waiver of Regulation

Commission approval of this Settlement Agreement shall constitute the requisite waiver of any and all otherwise applicable Commission regulations to permit the implementation of the provisions hereof and a determination that the settlement is fair, reasonable, and in the public interest and consistent with NGPA § 502.

Respectfully submitted,

WILLIAMS GAS PIPELINES CENTRAL, INC.

Gary W. Boyle/TKW

Gary W. Boyle
The Williams Companies, Inc.
P. O. Box 2400
Tulsa, OK 74102

January 31, 2001

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

FILED OFFICE OF THE SECRETARY 01 JAN 31 PM 3:29 REGULATORY COMMISSION

In Reply Refer To:
Williams Natural Gas Company
Docket No. RP93-109

Williams Gas Pipelines Central, Inc.
P. O. Box 2400
Tulsa, OK 74102

Attention: Gary W. Boyle, Senior Counsel

Reference: Offer of Settlement (January 31, 2001)

On January 31, 2001, Williams Gas Pipelines Central, Inc., formerly known as Williams Natural Gas Company ("Williams"), submitted for filing with the Commission an offer of settlement including a Stipulation and Agreement ("Agreement") dated January 31, 2001. The offer of settlement is in the public interest and is accepted and approved.

On April 30, 1993, Williams filed a general Section 4 rate filing proposing, among other things, to amortize over a three-year period actual past period costs of $4.2 million. On November 22, 1995, the Presiding ALJ issued an Initial Decision approving the three-year amortization of environmental costs with a procedure for refunding amounts which Williams recovered from third parties. On December 19, 1996, the Commission affirmed in part and reversed in part the ALJ's Initial Decision rejecting Williams' proposed amortization in favor of the "test period" method and ruling that the $1.4 million was a reasonable representation of the level of environmental costs to be recovered in rates. Williams appealed that decision to the D. C. Circuit Court of Appeals. This Agreement arises out of The D.C. Circuit Court of Appeals remanded the environmental cost issue to the Commission finding that it had not adequately explained why it had approved a $1.4 million annual environmental allowance. The active parties engaged in discovery, Williams filed direct testimony and all parties spent time discussing settlement. The Agreement represents a final, comprehensive resolution of environmental costs in this proceeding.

Pursuant to Rule 602(f) (18 C.F.R. § 385.602(f)(2000)) of the Commission's regulations, initial comments were filed on February 20, 2001, and reply comments were filed on March 2, 2001. Presiding Administrative Law Judge David I. Harfeld certified the offer of settlement to the Commission with the filed comments.

The Commission finds that settlement offer reflected in the Agreement is in the public interest and it is accepted and approved. The Commission's approval of this settlement does not constitute approval of, or precedent regarding, any principle or issue in this proceeding.

By direction of the Commission.

David P. Boergers
Secretary

xc: All Parties on restricted service list

The Commonwealth of Massachusetts

DEPARTMENT OF PUBLIC UTILITIES

May 25, 1990

D.P.U. 89-161

Generic investigation of the facts surrounding and the ratemaking treatment of the costs of investigating and remediating hazardous wastes associated with the manufacture of gas during the period 1822-1978.

APPEARANCES: James M. Shannon, Attorney General
By: George B. Dean, Esq.
James G. White, Esq.
Joyce Davis, Esq.
Carl D. Geisy, Esq.
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Petitioner

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Meabh Purcell, Esq.
LeBoeuf, Lamb, Leiby & MacRae
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FITCHBURG GAS & ELECTRIC LIGHT COMPANY
Petitioners

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Daniel R. Avery, Esq.
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FALL RIVER GAS COMPANY
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Petitioner

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<u>Petitioner</u>

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Donna D. Sharkey, Esq.
Keohane, DeTore & Keegan
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<u>Petitioner</u>

Alycia L. Goody, Esq.
Providence Gas Company
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Providence, Rhode Island 02903
FOR: NORTH ATTLEBORO GAS COMPANY
<u>Petitioner</u>

Andrew J. Newman, Esq.
Rubin & Rudman
50 Rowes Wharf
Boston, Massachusetts 02110
FOR: THE ENERGY CONSORTIUM
<u>Intervenor</u>

I. INTRODUCTION

A. Procedural Background

In Berkshire Gas Company, D.P.U. 89-112, the Department of Public Utilities ("Department") issued an Interlocutory Order on Environmental Cleanup Issues ("Interlocutory Order"), dated August 18, 1989. The Order was occasioned by a request from Berkshire Gas Company ("Berkshire") in that rate case to include expenses in its cost of service for cleanup of hazardous material at a site owned by Berkshire. Contamination of the site resulted from disposal of coal-tar wastes and other residues from the now-discontinued process of manufacturing illuminating and heating gas from coal and other feedstocks.[1]

The Interlocutory Order directed Berkshire to present evidence and argument on at least ten issues related to cleanup of such sites. In brief, the required information concerned (1) site descriptions, (2) description of gas manufacturing conducted at such MGP sites, (3) industry knowledge, standards, and practice about MGP waste disposal and environmental hazards, (4) legal requirements concerning MGP waste disposal, (5) conformity of MGP waste disposal practices to the gas industry's knowledge and practice and to the law, (6) manner of site

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1 These processes are referred to collectively as the manufactured gas process or "MGP" for short: hence, hereafter, "MGP plant sites," "MGP era," "MGP wastes," etc. See Section III of this Order for a description of the processes and their by-products and wastes.

acquisition, (7) insurance coverage in place, (8) description of environmental site reviews conducted preparatory to cleanup, (9) detailed cost estimates of cleanup work, and (10) appropriate ratemaking treatment of cleanup costs. Interlocutory Order, pp. 15-16.

B. Petition for a Generic Investigation

On July 18, 1989, Bay State Gas Company ("Bay State") petitioned the Department to initiate a generic investigation into the entire question of gas manufacture and environmental cleanup. The Department allowed that petition and opened the present docket. The Department designated James Connelly, Esq., as hearing officer. Technical staff of the Department's Rates and Research Division assisting in the investigation included Andrew Greene, Director, Paul Osborne, Linda Latham, and José Rotger.

On November 2, 1989, Bay State filed an amended petition ("Joint Petition") for a rulemaking proceeding in which it was joined by the Attorney General of the Commonwealth ("Attorney General"), Berkshire, Boston Gas Company ("Boston Gas"), Colonial Gas Company ("Colonial"), Commonwealth Gas Company ("ComGas"), Essex County Gas Company ("Essex"), and Fitchburg Gas & Electric Light Company ("Fitchburg"). The Joint Petition sought a generic inquiry, leaving apart site-specific investigations, into four of the issues listed in the Interlocutory Order: Issue 3, industry knowledge, standards, and practices; issue 4, legal requirements; issue 7, insurance;

and issue 10, appropriate ratemaking treatment. The Department also allowed the late-filed petitions of North Attleboro Gas Company ("North Attleboro") and Fall River Gas Company ("Fall River") to join in the petition and permitted the Energy Consortium, an association of industrial ratepayers, to intervene. On October 10, 1989, the Department issued an Order of Notice, requiring each gas company petitioner to publish notice, in accordance with the terms of G.L. c. 30A, § 2, and 220 C.M.R. 2.00 et seq., of the first public hearing in the docket on November 3, 1989.

Evidentiary hearings began on February 15, 1990 and ended on April 5, 1990 after seventeen days of testimony. The gas company petitioners jointly sponsored four witnesses to present in their case in chief: Kenneth F. Abraham, Esq., professor, University of Virginia Law School, Charlottesville; Andrew C. Middleton, principal, Remediation Technologies Inc., Pittsburgh, Pennsylvania; and William W. Hogan and A. Lawrence Kolbe, principals, Putnam, Hayes & Bartlett, Inc., Cambridge, Massachusetts. The Attorney General offered the direct testimony of Ronald H. Hill, industrial hygienist, Guilford County Health Department, Greensboro, North Carolina; and Timothy Newhard, financial analyst, utilities division of the Department of the Attorney General. The gas company petitioners also offered two rebuttal witnesses: Mr. Middleton and Barbara D. Beck, principal, Gradient Corporation, Cambridge. In addition to testimony given in the hearings, the evidentiary record consisted of 59 documentary exhibits sponsored by the gas company petitioners, 236 sponsored by the Attorney General, and 33 by the Department. The petitioners submitted simultaneous initial briefs on May 7, 1990.

C. Joint Motion to Approve a Settlement Agreement

On May 1, attorneys for the petitioner gas companies and the Attorney General ("Settling Parties") filed a Settlement Agreement ("Settlement Agreement") and accompanying Joint Motion for Approval of a Settlement Agreement and Termination of the Proceedings ("Joint Motion"). Ratification of the Settlement Agreement by their principals followed on May 4 and May 7 when executed copies of the agreement were filed with the Department. The Settlement Agreement is described and analyzed at length in Sections IV and V of this Order. In brief, the Settlement Agreement sets forth a detailed cost recovery mechanism to allow recovery over time of cost incurred to clean up MGP waste sites as directed by the cognizant environmental enforcement authorities. No objection to the Settlement Agreement was raised by any party to the investigation.

A second motion filed by the settling parties on May 10 sought extension of the date by which the Department would have to act upon the Joint Motion before the Joint Motion and the Settlement Agreement would expire on their own terms. The Department allowed the extension from May 15 to May 25. On May 18, the Settling Parties filed an amended second version of the Settlement Agreement. The amendments clarified possible ambiguities regarding the intended inclusion of the calendar year 1978 within the scope of Settlement Agreement. The amendments made no material change in the accord. On May 7, the Energy Consortium filed comments on the Settlement Agreement. The Energy Consortium expressed agreement with "the concept embodied in the Settlement Agreement," but suggested several modifications (Energy Consortium Comments, pp. 4-7).[2]

The remaining sections of this Order outline the legal, historical, and technical background of the production and cleanup of MGP wastes; describe the Settlement Agreement's provisions on recovery of MGP waste cleanup costs; analyze the Settlement Agreement in the context of the record assembled on the four issues that were the subjects of the Joint Petition; evaluate the Settlement Agreement against traditional ratemaking principles; and, finally, rule on the Joint Motion.

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2 Because the Joint Motion requires the Department to consider the Settlement Agreement in its entirety, we do not endeavor to rule on whether the individual modifications suggested by the Energy Consortium are appropriate. Rather, we consider the Energy Consortium's comments in the context of whether the Settlement Agreement, as presented, should be approved.

II. THE LEGAL IMPETUS FOR CLEANUP OF MGP SITES

The investigation in this docket entailed an assessment of acts of the petitioner gas companies (or others for whom they may be responsible) relating to manufacturing gas during the period 1822-1978, which acts may result in future legal liability. The legal impetus behind MGP site cleanup arises from environmental protection and remediation legislation developed over the past twenty years and enacted in both Federal and Massachusetts jurisdictions. This legislation seeks to arrest and reverse actual and potential environmental damage resulting from the disposal of hazardous material on land.

At the Federal level, the key enactments are the Resource Conservation and Recovery Act ("RCRA"), 42 U.S.C. § 6901 et seq. (1982 & 1987 Supp. V), passed in 1976, and the Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA"), 42 U.S.C. § 9601 et seq. (1982 & 1987 Supp. V), passed in 1980. In order to promote expeditious remediation of contaminated sites, CERCLA imposes joint and several liability, without regard to fault,[3] for investigation and cleanup of any

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3 Liability without fault under CERCLA and G.L. c. 21E is conceptually similar to, but, in fact, significantly distinguishable from the rule of strict or absolute liability under Rylands v. Fletcher, Law Rep. 3 H. L. 330, as adopted in Ball v. Nye, 99 Mass. 582 (1868). The distinction is important for purposes of our analysis, and so we note it early to emphasize it. Under Rylands and Ball, a plaintiff may recover damages for nuisance injury to his land without proof of (footnote continued)

such site on any person who generated, transported, or disposed of hazardous material there, who owned or operated the "facility" (42 U.S.C. § 9601[9]) where the hazardous material was generated, stored, or disposed, or who simply owned the land. The United States Environmental Protection Agency and Justice Department need make no showing of fault for liability

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negligence where a defendant "collects and keeps on his own land anything likely to do mischief if it escapes" and such escape, in fact, occurs. The defendant, it is said, "must keep it in at his peril[,] . . . is damnified without any fault of his own, and . . . should be held responsible to make good all damages, if he should not succeed in confining it to his own property." Fletcher v. Rylands, Law Rep. 1 Ex. 265 (Blackburn, J.), quoted in Shipley v. Fifty Associates, 106 Mass. 194, 198 (1870). Thus, since Ball was handed down, strict liability has effectively become a branch of nuisance (i.e., tortious interference with another's use of real property). Under CERCLA and G.L. c. 21E, on the other hand, escape of hazardous material from a landower's property onto that of another is not a necessary condition for liability to attach. The presence of such material in that part of the environment comprised by the landowner's property is alone sufficient. But cf. the observation of Mr. Justice Blackburn that the landowner's act of bringing "something on his property not naturally there" may be "harmless so long as it is confined to his own property." Id. Thus CERCLA and G.L. c. 21E extend strict liability well beyond the Rylands rule, which concerns the duty owed by landowners to one another, and establishes, in effect, the duty of each landowner to the sovereign to refrain, at his peril, from certain injuries to his own land as well as the land of others, all to advance the objective of environmental protection. Making a landowner liable to the state for injury to his own land (as distinct from restricting or enjoining uses obnoxious to neighbors or awarding damages for nuisance injury to a neighbor's land) is a great leap for the law and, arguably, a genuine discontinuity in its development (Tr. II, pp. 77-78).

to attach to a person in any of these categories. Dedham Water Co. v. Cumberland Farms, Inc., 689 F. Supp. 1223, 1225 (D. Mass. 1988). CERCLA seeks to protect against any release or threatened release of hazardous material, "release" being defined as "any spilling, leaking, pumping, pouring, emitting, emptying, discharging, injecting, escaping, leaching, dumping, or disposing into the environment." 42 U.S.C. § 9601(22).

The Massachusetts analogue of CERCLA is the Massachusetts Oil and Hazardous Material Release Prevention Act, G.L. c. 21E (1987), enacted in 1983.[4] Like its Federal counterpart, CERCLA, Section 5 of Chapter 21E establishes categories of person who may be strictly liable for costs or damages from the release or threatened release of hazardous material subject to certain exceptions long familiar in Massachusetts law. See Gorham v. Gross, 125 Mass. 232, 238 (1878); Cork v. Blossom, 162 Mass. 330, 333 (1894). Exceptions include acts of God, acts of war, and unforeseeable acts or omissions of third parties.

4 The record in D.P.U. 89-161 has benefited from the filing, at the hearing officer's request, of "Comments Regarding M.G.L. c. 21E Liability with Specific Reference to Coal Gas Sites" by Willard R. Pope, General Counsel, Massachusetts Department of Environmental Protection ("DEP") (Exh. DPU-32). Following the lead of G.L. c. 30A, § 14, the Department gives "due weight to the experience, technical competence, and specialized knowledge" of the DEP in setting forth our treatment of G.L. c. 21E in this Order. Bournewood Hospital v. Massachusetts Commission against Discrimination, 371 Mass. 303, 317 (1976).

G.L. c. 21E, § 5(c).

The Chapter 21E enforcement agency is the Massachusetts Department of Environmental Protection ("DEP"). That agency notifies persons who fit the statutory classes of liability known as Potentially Responsible Parties ("PRPs") of their potential liability by issuing a Notice of Responsibility ("NOR"). The DEP acts under what is known as the Massachusetts Contingency Plan ("MCP"), 310 C.M.R. 40.00 et seq., to identify, evaluate, and clean up sites contaminated by hazardous materials. Ideally, the DEP and PRPs work cooperatively to plan a voluntary evaluation and cleanup by the PRPs under DEP oversight. But DEP may also undertake to clean up the site on its own and seek recovery of its costs from the PRP later (Exh. DPU-32).

Cleanup of a site typically occurs in five phases. The first phase is the preliminary assessment to determine whether the property should be classified as a hazardous waste site under G.L. c. 21E and what priority status should be assigned to the site. The second phase systematically assesses the type, amount, and concentration of hazardous material on site and evaluates the threat to people or the environment posed thereby. The final three phases concern developing and effecting a plan for site remediation. If the threat is deemed imminent, short-term measures of may be warranted (id.). The remediation process is generally considered complex and costly (Exh. CO-2, pp. 43-50).

III. HISTORICAL AND TECHNICAL BACKGROUND

To establish the record context against which we have evaluated the Settlement Agreement, we trace the history of the MGP industry's development, identify the processes and feedstocks employed in manufacture, and discuss the process residuals that required disposal during the production years and may require remediation in the 1990s. The details are important to our analysis of the Settlement Agreement set forth in Section V.

A. Development of the Manufactured Gas Industry

The first practical application of gas produced by destructive distillation of coal is generally attributed to William Murdoch in 1792 (Exh. DPU-1, "Gas-Light," Encyclopaedia Britannica, 7th ed. [1842], p. 349, col. a). The first public exhibition of the MGP was made in 1802 by Phillipe Lebon in Paris (id., "Gas," Encyclopaedia Britannica, 11th ed. [1910], p. 483, col. a). In 1812, the Chartered Gas Light and Coke Company was authorized to light the streets of London with gas (id., col. b). In 1822, Boston Gas Light Company, the first gas company in Massachusetts and the second in the United States, was formed by a special act of the General Court (Exh. DPU-15-A, p. 7; Tr. III, p. 20). In the ensuing years, other gas companies were organized to supply gas to other cities and towns throughout Massachusetts through either special acts of the General Court or general corporation statutes (Exh. DPU-15-A).

Initially, the demand for gas was restricted to street lighting (Tr. III, p. 12). As technology developed, gas became available for indoor lighting, cooking, heating, and industrial demand (Exh. CO-2-A, p. 11). By 1900, manufactured gas works existed in many towns. Because the distribution mains of the time were of low pressure, gas works were only able to serve customers within a few miles of the plant (id., p. 14). Therefore, some larger cities had more than one gas works operating in the community (id.). Over the years, technological improvements allowed larger plants to be constructed, and many smaller plants were either consolidated or retired (id., pp. 14-15).

With the development of electricity in the late nineteenth century, the gas industry gradually lost its lighting business and concentrated on other markets, including domestic and commercial heating and cooking (id., p. 11). The development of gas appliances in the early 20th century made gas available for water heating, domestic laundry needs, and refrigeration (id., p. 13). Multiple industrial applications also created their demand during this period (id.).

The introduction of natural gas pipelines throughout the United States, starting in the late 1940s, sounded the death knell for the MGP. Because natural gas was a less costly fuel and had a higher British Thermal Unit ("Btu") content, it quickly supplanted manufactured gas as a base load supply source (Exh. DPU-18, p. 1). With the extension of natural gas pipelines into Massachusetts by the early 1950s, gas utilities generally converted to natural gas distribution. See Tatten v. Department of Public Utilities, 330 Mass. 360 (1953) (facts surrounding establishment of gas pipeline and eminent domain taking pursuant to St. 1950, c. 462). The gas utilities ceased manufactured gas production, with the exception of some high-BTU oil gas plants which were used for peak-shaving purposes into the 1960s and early 1970s (Exh. CO-2-A, pp. 13-14). The last operational manufactured gas works in Massachusetts, a high-Btu oil gas facility in Lowell, was retired in 1975 (Exh. DPU-6).

To make space available for other purposes, and to reduce property taxes, manufactured gas works were dismantled after their retirement (Exh. CO-2-A, p. 9). Decommissioning consisted of razing the above-ground structures to grade and using demolition rubble to fill in resulting holes (id., pp. 9-10). Below-ground tanks and pipes were purged of gas and left in the ground (Exh. DPU-29; Tr. XVII, pp. 91-93). Cinders and tar liquids were disposed of on-site, and spent oxides were disposed of both on- and off-site (Exh. DPU-29).

In 1985, the Radian Corporation issued a report ("Radian Report") listing 89 former manufactured gas works in Massachusetts (Exh. DPU-17). During the investigation in this docket, the petitioner gas companies reported that they had found an additional seven sites (Exh. DPU-6). This does not exhaust the list of MGP sites in Massachusetts, for the record indicates the existence of other gas utilities and MGP sites that are not found in the Radian Report and at least one additional MGP site in Brockton (Exhs. DPU-7; DPU-15-A). While many of the former manufactured gas works were operated by the petitioning gas companies or their corporate predecessors, other sites were operated by companies that are no longer in operation and have no relationship to the petitioning gas companies (Exh. DPU-6). A number of sites established by the gas company petitioners or their predecessors are still in use for utility-purposes (id.). Other sites had been sold over the years, and are no longer used in the gas industry (id.). At the present time, there are 24 former MGP plant sites on DEP's list of sites to be investigated and 17 sites where manufactured gas wastes were disposed (Exhs. DPU-4; DPU-5).

B. Manufactured Gas Processes

1. Coal Carbonization

The first significant method of manufacturing gas was the coal-carbonization process. Coal carbonization entailed burning a carbon in a closed retort, in the absence of oxygen. This method drove off volatiles (Exh. CO-2-A, pp. 17-13). The resulting gas was rich in hydrogen and methane and had a heat content of about 600 Btu per cubic foot (Exh. DPU-18, p. 25). Coal gas was used throughout the manufactured gas period (Exh. CO-2-A, Sch. 3).

The feedstock for the coal-carbonization process was coal or coke. Coal was extensively used until the 1890s, when the United States steel industry introduced by-product coke ovens

(Exh. DPU-18, p. 17). The development of the by-product coke oven made ample supplies of coke readily available as a feedstock in the coal-carbonization process (id., pp. 17, 19). The first by-product coke oven installed in the United States devoted to manufactured gas production was in Everett, Massachusetts, in 1898 (Tr. III, p. 45). Eventually, coke from by-product coke ovens became the major source of feedstock for manufactured gas operations (Exh. DPU-18, pp. 17-18).

2. Water Gas

Although there were experiments as far back as the 1780s concerning the effect of steam on heated carbon, a process for manufacturing gas by passing steam over a bed of incandescent carbon was first sucessfully developed by T.S.C. Lowe in 1873 (Exh. DPU-1, "Gaseous Fuel," Encyclopaedia Britannica, 10th ed. [1902], p. 602, col. a). In this process, steam reacts with the carbon to produce a fuel gas composed primarily of carbon monoxide and hydrogen (Exhs. AG-72; DPU-18, p. 24). As the resulting gas had a low heat content of about 300 Btu per cubic foot and contained few illuminants, or bright-burning hydrocarbons, water gas was produced primarily for heat rather than for illumination (Exh. DPU-18, p. 24). Because water gas burned with a clear or blue flame, it was commonly referred to as "blue" gas (Tr. III, pp. 108-109).

Shortly thereafter, it was discovered that by spraying a petroleum oil into water gas and running the mixture through a superheater, the molecules of vaporized oil and petroleum would chemically "crack" and break down into products that would remain in the gas steam, thereby raising the Btu content of the gas (Exhs. AG-73; DPU-18, pp. 110). The resulting gas had a heat content of about 600 Btu per cubic foot and was therefore suitable for illumination (Exh. DPU-18, pp. 109-110). Gas produced by this method was technically called "carbureted water gas," but was widely known as "water gas" (Exh. DPU-13, Tr. of September 10, 1888, pp. 2-3). Because the carbureted water gas process used equipment that had a longer useful life than coal carbonization retorts and because the process initially produced fewer residuals and provided for almost complete conversion of feedstocks to gas, carbureted water gas eventually became the predominant gasification process in the United States (Exh. DPU-1, "Gaseous Fuel," Encyclopaedia Britannica, 10th ed. [1902], p. 602, col. a).

3. Oil Gas

Carbureted water gas required both oil and a form of carbon as feedstocks. Although oil was readily available along the Pacific Coast, it was expensive to transport coke or coal to the region (id., pp. 15-16). This economic disadvantage led to the modification of the carbureted water gas process to eliminate the need for coal or coke (Exh. DPU-18, p. 42). Oil gas was made without coal or coke. The oil gas process involved injecting a mixture of steam and oil into a previously heated generator (Exh. AG-74). Oil gas was initially discovered in England in 1815, and the New York Gas Light Company relied exclusively on oil gas distilled from retorts until 1829 (Exhs. DPU-18, p. 42; DPU-1, "Gas," Encyclopaedia Britannica, 9th ed. [1879], p. 100, col. a). An oil gas technique using refractory materials was developed in 1889, and the first modern oil gas plant was installed in California in 1902 (Exh. DPU-18, p. 42). Oil gas was eventually used throughout the country (Exh. DPU-17). However, oil gas found only limited use in Massachusetts until after World War II (id., Exh. DPU-18, p. 46).

Because of the availability of natural gas starting in the late 1940s, a number of carbureted water gas plants were converted to high-Btu oil gas facilities to make a product compatible with natural gas (Exh. DPU-18, p. 43). The coke feedstock used in the water gas generator was replaced with a high-temperature refractory brick, and oil sprays and other oil-handling equipment were added (id., p. 51). These plant modifications enabled the production of a high-Btu content oil gas for peak demand at a relatively low cost (id.).

4. Other Processes

Other manufactured gas processes were used throughout the manufactured gas period. Some were variations of the processes just described, and others were distinct on their own terms. Exh. DPU-1, "Gaseous Fuel," Encyclopaedia Britannica, 10th ed. [1902], pp. 603-604) The latter included rosin gas, whale oil gas, acetylene gas, wood gas, peat gas, and petroleum gas (id., "Gas," Encyclopaedia Britannica, 9th ed. [1879], p. 100, col. a;

DPU-18, p. 57). Rosin gas, created by burning pine resin in heated retorts, and whale oil gas, created by burning whale oil in heated retorts, were used to a certain extent during the beginning years of the manufactured gas era, until the development of bituminous coal deposits in the United States around 1840 (Exh. DPU-18, pp. 54, 57). Because gas works using these processes tended to be small-scale operations which produced a mimimal level of wastes, sites that exclusively used these processes are expected to pose minimal hazards (id., p. 54).

Acetylene gas was produced by burning limestone and coal in an electric furnace, producing calcium carbide, which was then reacted with water (Exh. DPU-16, pp. 3-22). A number of small-scale gas works produced acetylene gas in Massachusetts at the turn of the century, but all of these had ceased operations by 1921 (Exh. DPU-15-A). The major waste product associated with acetylene gas was lime sludges, which, according to Mr. Middleton, do not pose an environmental danger (Tr. IV, pp. 111-112).[5]

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5 In addition, Buzzards Bay Gas Company manufactured butane-air gas from 1930 until 1946, when it added propane-air to its supply mix. 1946 Annual Return to the Department.

C. Residual Products From Manufactured Gas Operations

1. Description

The different production methods produced a variety of residuals.[6] The coal-carbonization process produced coke, coal tars, ammoniacal liquor, ash, and "clinkers."[7] (Exh. CO-2-A, Sch. 3). The introduction of by-product coke ovens required additional purification measures that resulted in the production of residuals including ammonium sulfate, naphthalene, light oil, and sludges (id., p. 20).

Besides ash, clinker, and spent oxides, water gas production left a variety of residuals, depending upon the feedstock used. These included water gas tars and water-tar emulsions (Exh. CO-2-A, Sch. 3). The initial use of naphtha as a feedstock in the carbureted gas process produced only traces of tar (Exh. DPU-18, p. 78). With the advent of the internal combustion engine, the increased demand for naphtha to blend with gasoline made naphtha less available for manufactured gas feedstocks (Exh. CO-2-A, p. 22). Light oils, and later, as these became less available, heavy oils, were substituted (id.,

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6 This section (Section III.C) of the Order catalogues MGP residuals and disposal practices. Section III.D discusses the evidence concerning the hazardous properties of MGP residuals and the risks attendant on the disposal practices. See infra, p. 24.

7 "Clinkers" are lumps of congealed ash (Exh. DPU-18, p. 153).

pp. 22-23). These feedstocks, particularly the heavy oils, increased the amount of tar produced and the need to remove sulfur from the manufactured gas (id.).

Major by-products from the oil gas process included lampblack, water-tar emulsions, and light oil (id., Sch. 3). Small amounts of ammonia, cyanides, tar bases, and tar acids were also produced (Exh. DPU-18, p. 46).

2. Composition of Residuals

MGP residuals contain a variety of chemicals, many of which are hazardous materials under CERCLA, 42 U.S.C. § 9601(14) and G.L. c. 21E, § 2. For instance, spent oxides contain sulfur, sulfide, sulfate, and tar (Exh. AG-106). For those spent oxides created by coal carbonization and by-product coke ovens, thiocyanate and cyanide are also present (id.). Polynuclear aromatic hydrocarbons, including benzopyrenes and tetracene, are present in water gas tar, coal tar, oil tar, and lampblack (id.; Exh. DPU-16, sec. 4, p. 30). Volatile aromatics are also found in these same tars and in light oil (Exh. AG-106). Phenolics are present in coal tar; and ammonia, cyanide, sulfide, and thiocyanate are present in ammoniacal liquor (id.).

3. Gas Purification Processes

Depending on the particular process used, various residuals associated with manufactured gas had to be removed prior to gas distribution. Certain components of raw or unpurified gas would condense in distribution mains, corrode pipes, or produce noxious gases at the burner tip (Exh. DPU-18, p. 54). Various cleaning and purification processes were used to prepare the gas for distribution, depending on the method of gas production and specific raw materials used (id.).

Water vapor and heavier tars were removed from coal gas by driving the raw gas through a hydraulic main, which was cooled to remove the water and heavy tars through condensation (Exh. DPU-18, p. 59; Tr. III, p. 64). In the case of water gas and oil gas, these vapors and tars were removed by passing the raw gas through a washbox. Lighter tars were removed both with direct and indirect condensers (Exh. DPU-18, p. 62). The remaining aerosols of tar were removed with either tar extractors or, after 1924, electrostatic precipitators (Exhs. AG-80; DPU-18, p. 62). At smaller plants, aerosols were removed by shavings scrubbers (Exh. DPU-18, p. 65). Tar from coal-gas works could be resold to industry, but tar produced at carbureted gas and oil gas plants generally contained petroleum derivatives which made them less suitable to industry (Tr. III, p. 102). Tars produced by coal carbonization were often recycled as process fuel where the water component was proportionately small enough not to retard combustion (Exh. DPU-18, p. 133).

Tars with a high water content were referred to as tar-water emulsions (id., p. 136). Emulsions were not generally a problem at coal carbonization plants, for the tar separated cleanly from the condensates and each could be readily recovered (id.). However, tar-water emulsions produced by carbureted water gas and oil gas facilities often contained too much water either to sell or to burn (id., p. 136). In these cases, the tar-water emulsions were simply disposed of on-site into holding lagoons or pits, or off-site into streams or along railroad tracks (id., p. 134).

Naphthalene was frequently removed from the gas by scrubbing with oil (Exhs. AG-77; DPU-18, p. 69). The naphthalene-enriched oil could then be distilled to recover the naphthalene for resale, if market conditions warranted it, or used in the carbureted water gas or oil gas process (Exh. DPU-18, p. 69).

Initially, light oils were not removed from the gas (id., p. 72). In later years, the demand for benzene and xylene chemicals during World War I spurred the recovery of light oils in the same manner as was used for naphthalene recovery (id., p. 69). Scrubbers were used to recover the oil, which was then either mixed with light oils or carburetion stocks for resale or use as a feedstock, or merely discarded with condensate water (Tr. III, pp. 149-150; Exh. DPU-18, p. 67).

Condensate water was also produced by the tar-extraction process (id.). Because retorted coke could spontaneously combust, it had to be quickly quenched with water to preserve the coke as it left the anoxic environment in the retort (Exh. AG-236). This need provided a use for the condensate water as a coke quencher (Exh. DPU-18, p. 67). Otherwise, the condensate was recycled or disposed of in streams (id.).

Ammonia was removed through several methods, including treatment with sulfuric acid or through ammonia stills (Exhs. AG-78; DPU-18, pp. 78, 81). Phenols were either discharged into city sewers, used as a quenching agent for coke removed from the ovens, or, if recovery was desired, extracted by washing or vapor recirculation (id., pp. 84, 86).

Hydrogen sulfide was initially removed with lime (id., p. 88). Because lime could only be used once, it was an expensive process (id., p. 90). Beginning around 1870, it was discovered that iron oxide could remove hydrogen sulfide, and be reused (id., p. 190; Tr. III, p. 87). Iron oxide could be regenerated either by exposure to air over several months or by blowing air through the purifier box (Tr. III, pp. 152-153). Eventually, the iron oxide became so contaminated with sulfur that it could no longer regenerate and was itself discarded (id., p. 152). During the 1920s, several liquid purification processes were developed for hydrogen sulfide removal (Exh. DPU-18, pp. 92-93, 193).

Cyanide was produced by coal carbonization and removed from coal gas by the same equipment that removed hydrogen sulfide (id., p. 99). Only trace quantities of cyanide were generated by carbureted water gas and oil gas, so its recovery for resale was profitable only at larger plants (id.).

4. Disposition of Residuals

Residuals may be broken down into two categories: by-products and wastes (Tr. III, p. 16). If by-products had the proper chemical constituents and energy content, they could be recycled as a feedstock in the manufactured gas process (Exh. CO-2-A, p. 23). Alternatively, certain residuals, including coke, various tars, and ammonia, could be used in other industries (Exh. DPU-18, p. 132). By selling by-products, gas companies could reduce net production costs, and thereby offer customers a lower-cost product and encourage greater sales (Exhs. CO-2-A, p. 26; DPU-13, Tr. of September 10, 1888, p. 5). Despite the benefits to gas customers and utilities that could be accrued through the sale of by-products, the extent to which by-products could be sold was influenced by available recovery technologies and by whether sufficient by-products could be generated to make resale economically practical (Exh. CO-2-A, p. 26). The prevailing market that existed from time to time for a particular by-products also influenced the decision as to resale or disposal (id.).

Certain residuals, such as ash and clinkers, had little, if any, market value. These wastes were often discarded either on- or off-site as fill material (Exh. DPU-18, p. 153). Even for those residuals with resale value, prevailing market conditions dictated whether the residual could be sold. Although spent oxides were reclaimed in Europe for sulfuric acid, the abundance of brimstone in this country made sulfur readily available and left spent oxides with little, if any, market (id., p. 144).

The use of tar as a by-product in this country was generally limited before World War I, because of the availability of tar-based products, including chemicals and pharmaceuticals, from Germany (Exh. DPU-27, p. 14).

In addition, the physical characteristics of the tars produced by carbureted water gas and oil gas plants limited their value. Unlike tars from coal carbonization plants, tar-water emulsions produced by carbureted water gas and oil gas facilities were of irregular quality and generally contained too much water to burn (Exh. AG-208, p. 1239). These wastes were generally disposed of on- or off-site (Exh. DPU-18, p. 136).

D. State of Scientific and Engineering Knowledge Concerning the Hazards of MGP Wastes

The occupational hazards of coal combustion products were documented as far back as 1775 (Exh. AG-158). At that time, the effect was believed to be caused by mechanical irritation of the skin by soot (Exh. CO-10; Tr. XIII, p. 134). By 1876, a connection between coal tar and cancer, long suspected, was conclusively established (Tr. XII, p. 104). It still remained unclear whether cancer was caused by chemical effects of coal soot on the skin or by mechanical irritiation (Tr. XIII, p. 137; Exh. CO-10, p. 5). Experiments during the early nineteenth century sought to establish what chemical fractions of coal caused cancer; and the link between the chemical properties of coal tar to cancer was established by the late 1920s and early 1930s (Tr. XIII, p. 139; Tr. XII, pp. 109). Benzo(a)pyrene, a major carcinogen found in coal tar, was first identified in 1933 (Tr. XIII, pp. 146-147). Other carcinogens were identified in 1947 (Exh. AG-154).

Another chemical component of MGP wastes, benzene, was known as a hematological poison since the late nineteenth century (Exh. AG-99, p. 18). Benzene causes aplastic anemia (Exh. AG-178, p. 4; Tr. XIII, p. 109). Though medical science had long seen a linkage between benzene and leukemia, the first clear establishment of benzene as a human leukemogen was made in 1977 (Tr. XIII, p. 109).

Throughout the MGP era, the scientific and medical communities developed the connection of MGP wastes to human health risks. What was lacking was the determination of the level at which public health might be adversely affected by MGP wastes (Tr. XIII, p. 112). While the medical observations of the period may have been precise and based on comprehensive data collection, the relationship between the level of exposure to MGP wastes and the reaction to the exposure was still uncertain (id.). The statistical analyses now used to determine dose-response levels, including multievent modeling, were not developed until 1976 (Exh. CO-42; Tr. XII, pp. 11, 153). The technical ability to detect contaminant levels required under current occupational safety and environmental regulatory standards did not exist until the 1970s (Tr. XII, pp. 11, 153; Exh. CO-41).

The record is replete with scientific inquiry and debate over the causes of recognized health hazards as far back as 1775 (Exh. AG-158). However intense the debate over causation may have been, there seems to have been little dispute over recognition of adverse occupational health effects.

By the late 1800s, the state of knowledge associated with MGP wastes was sufficient to induce passage of environmental regulatory measures with respect to waterways. The disposal of tar and other MGP wastes into waterways was generally restricted or prohibited, by either local or state action (Exhs. AG-193, p. 342; AG-165).

Evidence contemporaneous to the MGP era demonstrates a degree of awareness by the gas industry that MGP plant operators were collecting on their land materials that represented environmental hazards and whose escape could cause injury to others. The gas industry seems generally to have understood that certain properties of MGP wastes were deleterious (Tr. XVII, pp. 79-80). For example, the disposal of spent oxides on land damaged land, leaving the particular parcel unsuitable for agricultural purposes (Exh. AG-128; Tr. VI, pp. 79-80; Tr. XI, pp. 133-134; Tr. XVI, p. 36). The industry was also concerned that the various salts and chlorides contained in ammonia still waste may have had a detrimental effect on vegetation (Tr. XV, pp. 132-133; Exh. AG-168, p. 454). It was also known that the introduction of MGP wastes into a waterway could damage oyster beds and kill fish (Exhs.

AG-167, pp. 349-350; AG-193, p. 342; Tr. XVI, pp. 36-37). Gas liquors were known to be highly toxic to fish, and rendered them unpalatable by the concentration of chemicals in the flesh (Exhs. AG-129, p. 126; Exh. AG-167, pp. 349-350; Tr. XII, pp. 67-68; Tr. XV, pp. 126, 129).

A major concern of the manufactured gas industry during this era was the potential for contamination of water supplies by the escape of MGP wastes from MGP sites. MGP wastes deposited on the ground could seep into wells and streams and render the water unpalatable whether by taste or odor (Exh. AG-128, p. 315; Tr. XII, pp. 51, 71). The disposal of ammonia wastes into the ground was considered to be a hazardous proposition because the waste could percolate into ground water and end up in a stream (Tr. XII, pp. 85-86). It was generally known that tar water waste contained hazardous constituents, including napthalene, benzene, toulene, and xylene (Exh. AG-167, pp. 349-350). Despite the relatively limited state of hydrogeologic science, the MGP industry was aware that the discharge of these substances in concentrated form could produce adverse effects (id., p. 349).

Correspondingly, MGP operators realized the need to avert risk to the property of others from MGP waste nuisances. Concerns at industry meetings revolved around the possibility of successful legal actions against MGP operators on charges of nuisance (Exh. AG-128, pp. 314-315) (see also Section V.B.). Nuisance actions could, and were brought on a number of grounds, including damage to land, vegetation, and waterways (id.; Exh. AG-100, p. 444; Tr. XI, pp. 130-131). Other causes of legal action cited by industry officials during this period included complaints of tarry wastes carried off by streams and later found adhering to the legs of cattle and injuring soil and crops (Exh. DPU-129, p. 128; Tr. XII, pp. 76-78).

In such circumstances, industry officials were urged to take such measures necessary to prevent any nuisance from being found at their facilities, thereby averting legal actions (Exh. AG-128, pp. 314-315). Measures taken to minimize the possibility of MGP waste's escape included the development of equipment to extract tar from water and to burn tar as boiler fuel (Exhs. AG-194, p. 226; AG-198, p. 158). The trade journals and industry meetings of the MGP era are replete with information concerning the various alternatives available to treat or dispose of MGP wastes (Exhs. AG-167, AG-198; AG-201; AG-202; AG-204; AG-211; AG-218; AG-221). Various recommendations were made as to what specific plant improvements or processes could be used to eliminate or mimimize problems associated with MGP wastes (Exhs. AG-203; AG-205; AG-206, passim). The American Gas Association's various committees were actively considering the most appropriate methods to treat MGP wastes during this period (Exhs. AG-199; AG-206 [Willien]; AG-208; AG-210; AG-213; AG-214). Finally, individual gas utilities reported in the trade journals of the period on the measures they had taken to minimize the problems associated with the disposal of residuals (Exhs. DPU-12 [Carter]; DPU-26, Sec. 7, pp. 59-81; AG-206 [Klein]; AG-211; AG-217; CO-58; CO-59).

IV. DESCRIPTION OF SETTLEMENT AGREEMENT

On May 1, 1990, the Settling Parties jointly filed a Settlement Agreement. The Energy Consortium refrained from participating in the Settlement Agreement but filed comments in its brief. In the Settlement Agreement, the Settling Parties agreed that, beginning on July 1, 1990 ("the Implementation Date"), each of the gas company petitioners would amortize and recover from their ratepayers over a seven-year period, without carrying charges, the environmental response costs incurred during 1989 (Settlement Agreement, § II). Previously deferred response costs would be treated in the same manner as if they had been incurred during 1989 (id., § VIII). Cleanup costs incurred each year in the future would also be recovered over separate, seven-year amortization periods. The Settling Parties agreed on this compromise for ratemaking purposes without any finding regarding the prudence of the manufactured gas operations and plant decommissioning (id., Preamble).

The Settling Parties propose a definition of recoverable "environmental response costs" to include all investigation, testing, remediation, litigation expenses, and other liabilities relating to manufactured gas facility sites, disposal sites, or other sites onto which material may have migrated, as a result of the operation or decommissioning of Massachusetts gas manufacturing facilities during the period from 1822 through 1978 (id.). The Settling Parties indicate that personal injury settlements or awards relating to manufactured gas waste sites would be considered recoverable costs within the definition of the term "environmental response costs" (Tr. of May 9, 1990, p. 10 et seq.). The gas company petitioners made a representation that they are not aware of any personal injury suits or claims relating to the pre-1979 manufactured gas operations, waste disposal and decommissioning activities, and are also not aware of any facts that would lead them to believe that any such suits or claims will be filed or asserted (Settlement Agreement, § VII.C; Tr. of May 9, 1990, pp. 12-27). The Settling Parties specifically excluded from recoverable costs any expenses resulting from claims made by the gas company petitioners against insurance companies or third parties,[8] or any expenses resulting from any non-manufactured gas operations, including but not limited to by-product coke oven sites, the Plympton lead site, or PCB sites (id., § VII.A).

Under the Settlement Agreement, the Settling Parties propose that the agreement would preclude any party to the Settlement Agreement (or the Department on its own motion) in a later proceeding before the Department from challenging the propriety of recovery from ratepayers of the environmental response costs on grounds of (a) the prudence of the pre-1979 manufactured gas

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8 Expenses and recoveries resulting from claims against insurers or third parties are addressed separately in the Settlement Agreement, § VI, as described infra, p. 34.

operations, waste disposal, and decommissioning activities that have resulted in the need for incurring the response costs or (b) the appropriateness of allowing rate recovery of such expenses through the recovery mechanism provided for in the Settlement Agreement. In the Settlement Agreement, the Attorney General reserved his right to challenge or contest the prudence of any action taken or not by the gas company petitioners and the amount of any costs or recoveries incurred or obtained through the prosecution of insurance and third party claims (id., § VII.B; Tr. of May 9, 1990, p. 5). The authority of the Department in this regard remains, of course, unimpaired by the terms of the Settlement Agreement.

The Settlement Agreement provides for a recovery mechanism in the form of a separate, additional element in the existing Cost of Gas Adjustment Clause. 220 C.M.R. 6.00 et seq. This element, the Remediation Adjustment Clause, would provide for a per-unit-of-gas charge equal to sum of the charge to be collected under the company's current Cost of Gas Adjustment Clause and the amount given by the environmental response cost formula (Settlement Agreement, § IV.A). This formula would consist of one-seventh of the actual response costs incurred by a company in a calendar year and to be recovered from ratepayers during the upcoming year, less a deferred tax benefit to be returned to ratepayers during the upcoming year. This amount would then be divided by the company's forecast of total firm sales volumes for the upcoming year. The Settling Parties further agreed that the environmental response cost portion of the Cost of Gas and Remeditation Adjustment Clause would be reconciled annually for each company, with the amount of any over or under collection to be debited or credited to the total annual charge for the following year (id., § IV.C).

The deferred tax benefit would be calculated as follows. For the first year of cost recovery, the deferred tax benefit would be the amount given by the entire actual response costs incurred in a calendar year multiplied by the company's net cost of capital rate (as set in the company's last base rate case and adjusted for income tax effects) and by the effective combined federal and state income tax rate. In the second year, six-sevenths of the actual response costs would be multiplied by the cost of capital and the combined tax rate; in the third year, five-sevenths of the costs would be used, and so forth until the seventh and final year, when one-seventh of the response costs would be used (id., § IV.B).

With regard to filing requirements, the Settlment Agreement requires that each company file with the Department, the Attorney General, and any other interested party all bills and receipts relating to any environmental response costs incurred in the preceding calendar year for which each company seeks to begin recovery in the upcoming year and a schedule depicting the purpose of each expenditure. This filing would occur at least ninety days before each anniversary of the implementation date. In the same filing, each company would include similar material and information to support any expenses or recoveries from insurance or other third-party claims (id., § IV.D).

The Settlment Agreement accords a different ratemaking treatment to insurance and third-party litigation expenses and recoveries. Insurance and third-party expenses and recoveries would be shared in equal proportions between the gas company petitioners and their ratepayers. In the Settlement Agreement, one half of the expenses incurred by the gas company petitioners in the prior year in prosecuting insurance and third-party claims and one half of any recoveries or other benefits received by the gas company petitioners as a result of a judgment or settlement from insurance or third-party claims, would be credited against all annual amortization amounts that have been or are being collected through the Settlement Agreement's recovery mechanism (id., § VI).

The Settlement Agreement also provides a limitation on the total annual charge to be recovered from ratepayers: the total annual charge to a company's ratepayers would not exceed five percent of a company's total revenues from firm Massachusetts gas sales during the preceding year. If for a particular company, the annual recovery should exceed the five-percent cap, the amount in excess of the cap would be deferred and would accrue carrying charges at the company's net cost of capital (as allowed in the company's last rate case and adjusted for income tax effects) until such sum can be added to the amount to be recovered in a subsequent recovery year without exceeding the five-percent cap (id., § V).

The terms of the Settlement Agreement provided for an option to discontinue the agreed upon ratemaking treatment. Any company whose 1989 firm retail gas revenues were less than $100 million may choose to discontinue the ratemaking treatment of the environmental response costs provided for under the Settlement Agreement in the event that the unrecovered amount of its response costs should exceed the lesser of $2 million or 5.5 percent of its 1989 firm gas distribution revenues (id., § IX). The gas company petitioners for which this provision is applicable are The Berkshire Gas Company, Essex County Gas Company, Fall River Gas Company, Fitchburg Gas & Electric Light Company, and North Attleboro Gas Company.

If a company does provide written notice that it intends to exercise this right, then, as of the first day of the month following the date of notice, the company would no longer be allowed to recover any response costs through the mechanism provided for in the Settlement Agreement (id., § IX.A). Furthermore, any balances remaining in the company's environmental response cost account would be treated for ratemaking purposes as if they had been granted deferral of their recognition and thus not subject to disallowance for the sole reason that they occurred prior to the particular test year used by the company in pursuing rate recovery (id., § IX.B). The company may also seek base rate treatment of the balance remaining in its environmental response cost account and any response costs that it may incur in the future, plus any expenses or recoveries resulting from insurance or third party claims (id., § IX.C). In addition, the company would bear the burden of proof with regard to the prudence of the environmental response costs for which it seeks or has received recovery from its ratepayers as if the Settlement Agreement had never occurred and it was seeking recovery of these costs for the first time. The Attorney General would then be free to challenge and the Department free to investigate the prudence of the manufactured gas operations and decommissioning activities of the company that resulted in the need to incur the response costs and the propriety of allowing rate recovery of such expenses (id., § IX.D). Finally, if the company initiates a rate proceeding for recovery of response costs, the amounts of any previous recoveries of response costs found to be reasonable by the Department in this proceeding would be credited against the amount of such response costs, if any, found to be recoverable from ratepayers in the Department's decision in that proceeding. Similarly, any amount of previous recoveries of such costs found by the Department to be unreasonable would be credited against the revenue requirement found in that proceeding (id., § IX.E).

The Settling Parties further agreed that in the gas company petitioners' future rate cases environmental response costs would not be considered in determining the level of base rates. The gas company petitioners agreed that they will not make any arguments in a subsequent rate case that the existence of the

Settlement Agreement or the effects resulting from its application justify the allowance of a higher rate of return on common equity (id., § X).

Finally, the Settling Parties agreed on the treatment to be given to gains from future sales of affected properties. In the event a company sells a former manufactured gas operations or dump site and realizes a net gain on the sale, the company would be allowed to calculate its basis in such property (for purposes of the determining the gain to be returned to its ratepayers) by including the carrying costs foregone during the amortization period on those response costs related to said property; provided that such adjustments to the company's basis do not result in the gain becoming a loss (id., § XI).

V. ANALYSIS OF THE SETTLEMENT AGREEMENT ON THE BASIS OF THE GENERIC RECORD

We have reviewed the Settlement Agreement on the basis of the generic investigation record in this docket and generally find it to be in ratepayers' interest. We therefore allow the Joint Motion. In this section, we set forth our reasons for accepting the Settlement Agreement. While refraining from any prudence findings, we describe our conclusions concerning the four issues examined in this docket: industry knowledge and practice, the law of the MGP era, insurance coverage, and appropriate ratemaking treatment, as set forth in the Interlocutory Order and in the Joint Petition. In turn, we assess the Settlement Agreement against our conclusions to indicate the reasons for its acceptability.

A. Industry Knowledge and Practice

Our review of the record in Section III of this Order persuades us that throughout the MGP era, the industry knew either in fact or constructively that the by-products and wastes of the MGP processes were hazardous and, in some cases, were carcinogenic and that the deposition of such materials on land or in ground or surface waters could injure that land or those waters by rendering them unfit for certain purposes. There is evidence, of course, that the ethic of the era sanctioned the use of land for such purposes. And there is further evidence that the economics of marketing MGP by-products were often so adverse as to render disposal of by-products on site or at authorized dumpsites a more rational alternative than attempted sale, as a matter of short-run economics.

This awareness of the hazardous nature of MGP wastes does not, however, readily translate into imprudence for incurring the kind of liability imposed today by CERCLA and G.L. c. 21E. Even though this awareness may have alerted MGP operators to the risks to others and to neighboring land from MGP wastes, it is difficult, though not impossible, to infer that an MGP operator ought to have known that mere disposal on his own land or at a legal dumpsite, where no escape has subsequently occurred onto neighboring property, would leave him or his successors liable to clean up his own land or the dumpsite as part of a government-ordered remediation some two, ten, or even seventeen decades later. And even if such potential liability should have been foreseen, there would remain the difficult question whether such disposal might fairly be judged imprudent or whether risk of incurring a liability, arguably so remote, should better be viewed as a reasonable cost of doing business. The difficulty of inferring a want of care in MGP disposal practices is heightened by the evidence that the ability to measure the presence and effects of environmental contaminants at the parts-per-billion level of dilution in water was quite unknown to science during the MGP era.

Where, however, the land of others might become implicated by later escape of MGP wastes, the inference of want of care or prudence might more readily be drawn. But even there, as we point out in our discussion of the law of the MGP era that follows, such an inference, while arguably strong, is not compelled.

It is a virtue of the Settlement Agreement that these difficult judgments are rendered unnecessary. In their place, a reasonable cost-sharing mechanism is established.[9] Therefore, unless and until a company entitled to invoke Section IX of the Settlement Agreement, permitting discontinuance of its ratemaking treatement, acceptance of the Settlement Agreement altogether obviates any need to render prudence judgments on the knowledge and practices of the MGP industry. We confine ourselves to observing that the Settlement Agreement's cost-sharing approach, taken as a whole, is not inconsistent with our reading of the record and of defensible inferences that might be drawn from it on the issue of industry knowledge and practice.

B. The Law of the MGP Era

Understanding MGP-era law is a key to establishing the rights and duties of MGP plant operators and their prudence in the conduct of their business. Interlocutory Order, pp. 15-16. As noted earlier, the Settlement Agreement, § II, would obviate

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9 The cost-sharing mechanism provides for an approximately 50/50 sharing of cost between company stockholders and ratepayers (Tr. of May 9, 1990, pp. 28-29). The mechanism is analyzed in Section V.D of this Order, infra, p. 50.

any need for such prudence inquiries or findings on the part of the Department. Nonetheless, the Department has investigated the MGP-era law as part of this docket and must view the acceptability of the Settlement Agreement against that background, although, as noted, we refrain from any express finding on the prudence question.

Accordingly, we review the Settlement Agreement against pre-CERCLA law concerning (a) rights to use and restrictions imposed on the use of land generally, (b) duty owed by one landowner to another, and (c) defenses and liabilities resulting from use of independent contractors to haul, dispose of, or receive MGP wastes. The law sheds light on rights and duties in the use of MGP plant sites and legal dumpsites and on obligations to neighboring land onto which MGP wastes may have migrated.[10]

The pertinent law is tort law and real property law. We well recognize, of course, the need for caution in "reliance on tort analogies to define a public utility's responsibility in a

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10 Finding the law of the MGP era, before the major change wrought by CERCLA, is akin to the exercise undertaken by Federal courts to determine state law in diversity suits. 28 U.S.C. § 1652. As there may not always be precedent exactly on point, courts look to relevant precedents, analogous decisions, and considered dicta. Nolan v. Transocean Air Lines, 365 U.S. 293, 295-96 (1961); Sproul v. Hemmingway, 31 Mass. [14 Pick.] 1, 5 (1833); Gray v. Boston Gas Light, 114 Mass. 149, 154 (1873). See C. Wright, Law of the Federal Courts, § 58, at 370 (4th ed. 1983).

regulated area." Commonwealth Electric Co. v. Department of Public Utilities, 397 Mass. 361, 367 (1986). But at least until the late 1920s, the MGP era was largely a time of no or of limited regulation of the gas industry (Exh. AG-117, pp. 25-26; Tr. XVII, p. 94). Thus, the best touchstone available is tort and real property law.

During most of the MGP era, land-use regulation was, when compared with late twentieth-century practice, rudimentary. R. Anderson, American Law of Zoning 3d, § 3.03, at 86, § 3.06, at 93 (3d ed. 1986); D. Hagman and J. Juergensmeyer, Urban Planning and Land Development Control Law, § 2.2, at 13, § 2.3, at 14 (2d ed. 1986). In the absence of a legislative or police restriction or of a covenant, a proprietor could "consult his own convenience in his operations above and below the surface of his ground." Greenleaf v. Francis, 35 Mass. [18 Pick.] 117, 121, 123 (1836). See Shipley v. Fifty Associates, 106 Mass. 194, 197 (1870). Ownership was a coelo usque ad centrum ("from heaven to the center of the earth"), and ownership rights could be asserted even at some inconvenience to neighbors. Greenleaf, 35 Mass. [18 Pick.], at 117, 121-22; Gannon v. Hargadon, 92 Mass. [10 Allen] 106, 109-10 (1865). Locale was a major determinant of whether legislative or police restrictions on certain uses were warranted. Commonwealth v. Tewksbury, 52 Mass. [11 Met.] 55, 57 (1846); Commonwealth v. Alger, 61 Mass. [7 Cush.] 53, 87, 95-96 (1851). Even where restriction on the use of private property for trades "useful and beneficial to the public" was warranted, id., it was to be exercised "only in cases amounting to an obvious public exigency." Tewksbury, 52 Mass. [11 Met.], at 57-58; Alger, 61 Mass. [7 Cush.], at 97, 102-03. Very little indication appears on our record (which is, albeit, generic and not site-specific) regarding legislative or police restrictions of the MGP industry. Indeed, if any inference is warranted, one of a favorable legislative view of the gas industry may perhaps be drawn from the frequent grants of corporate charters by special acts of the General Court (Exh. DPU-15-A).

Although landownership rights were broad during the MGP era, landowners were responsible for certain adverse consequences of use. Private ownership rights were tempered by the common law principle sic utere tuo ut alienum non lædas ("use your own property in such a way that you do not injure that of another"). Public or private nuisance[11] actions might lie for transgression of this maxim. Stowell v. Flagg, 11 Mass. 364, 364-65 (1814); Thurston v. Hancock, 12 Mass. 220, 224 (1815); Tewksbury, 52 Mass. [11 Met.], at 57. Even so, a landowner still retained the right "to use his land to his best advantage." Eames v. New England Worsted Co., 52 Mass. [11 Met.] 570, 572 (1846).

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11 "A public nuisance is an unreasonable interference with a right common to the general public." Restatement, Second, Torts, § 821B. "A private nuisance is a nontrespassory invasion of another's interest in private use and enjoyment of land." Id., § 821D.

But where injury ensued "from an otherwise legitimate use" of his property, the landowner would have to "compensate his neighbor in damages" for the resultant nuisance, Stowell, 11 Mass., at 364-65, even where the damage was modest, Eames, 52 Mass. [11 Met.], at 572, and even where the result might be impossible to control or difficult to predict. Wilson v. New Bedford, 108 Mass. 261, 265 (1871). See also Sherman v. Fall River Iron Works, 84 Mass. [2 Allen] 524, 526 (1861); Sherman v. Fall River Iron Works, 87 Mass. [5 Allen] 213, 214-15 (1862); Shaw v. Cummiskey, 24 Mass. [7 Pick.] 76 (1828); Monson & Brimfield Manufacturing Co. v. Fuller, 32 Mass. [15 Pick.] 554 (1834); Fuller v. Chicopee Manufacturing Co., 82 Mass. [16 Gray] 46 (1860); Shipley, 106 Mass. 194. Nuisance liability might even attach for acts related to land not in the defendant's possession. Gray v. Boston Gas Light, 114 Mass. 149, 154 (1873). Moreover, a landowner was responsible not only for erecting a nuisance of his own, but also for maintaining a nuisance earlier erected on the land by another. Staple v. Spring, 10 Mass. 72, 74 (1813); Eames, 52 Mass. [11 Met.], at 572-73.

Before 1868, violation of duty to refrain from nuisance required a showing of "culpable negligence." Chandler v. Worcester Mutual Fire Insurance Co., 57 Mass. [3 Cush.] 328, 330 (1849). After 1868, a plaintiff no longer had to show negligence for certain kinds of injury to his land, for strict or absolute liability might attach. Ball v. Nye, 99 Mass. 582

(1868), adopting the rule of Rylands v. Fletcher, Law Rep. 3 H.L. 330 (1868). Where a landowner brought or collected "something on his own property not naturally there, harmless so long as it is confined to his property, but . . . mischievous if it should get upon his neighbor's land," he would be held, despite his best efforts to contain what he had collected, "responsible for damages, if he should not succeed in confining it to his own property." Shipley, 106 Mass., at 198. See Fuller, 82 Mass. [16 Gray] 46; Shipley, 106 Mass., at 199; Wilson, 108 Mass., at 265-66; Fitzpatrick v. Welch, 174 Mass. 486 (1899); Deyo v. Athol Housing Authority, 335 Mass. 459, 462-63 (1957). The Rylands rule did not enlarge a landowner's duty to refrain from injury to another's property. Rather, Rylands, as adopted in Massachusetts, merely eliminated the need to prove negligence and, in effect, put certain hazardous uses of land "at the sole risk of the user," who henceforth had to provide "safeguards [against escape] whose perfection he guarantees." Ainsworth v. Lakin, 180 Mass. 397, 399 (1902).

Although the Rylands rule was denominated one of strict liability, it was not unqualified. As stated earlier, supra page 8, certain defenses, such as acts of God or unforseeable and wrongful acts of third parties, were available. Cork, 162 Mass., at 333. Moreover, the injury had to be the natural consequence of the breach of duty. Kaufman v. Boston Dye House, Inc., 280 Mass. 161, 169 (1932).

Use of an independent contractor might offer a defense to liability. Brackett v. Lubke, 86 Mass. [4 Allen] 138, 140 (1862). Cf. Foster v. Essex Bank, 17 Mass. 479, 509 (1821). But even that defense could be overcome where an independent contractor "was without proper skill or unsuitable to do the work," Connors v. Hennessey, 112 Mass. 96, 99 (1873), or where improperly done work caused "mischief upon the land of another." Gorham, 125 Mass., at 99. See Connors, 112 Mass., at 99; Sturges v. Society for the Promotion of Theological Education at Cambridge, 130 Mass. 414, 415 (1881); Davis v. John L. Whiting & Son Co., 201 Mass. 91, 93 (1909); Pickett v. Waldorf Systems, Inc., 241 Mass. 569, 570 (1922). Use of an independent contractor by a public utility defendant might also prove an unavailing defense where statute imposed a duty. Boucher v. New York, New Haven, & Hartford Railroad Co., 196 Mass. 355, 359-60 (1907). Cf. Commonwealth Electric, 397 Mass., at 366 n.2. But even apart from statute, common law liability might attach for the wrongful consequences of the acts of an independent contractor performing under a lawful contract. Woodman v. Metropolitan Railroad, 149 Mass. 335, 339-40 (1889), citing Gorham, 125 Mass., at 240.

Having examined the law of the MGP era, we make several observations about applying it to prudence inquiries. Considering the passage of time, the unavailability of percipient witnesses to the events likely to be at issue in prudence inquiries, the general state of company records, and the condition of MGP plant sites (many of which have been dismantled and redeveloped), we regard applying these principles of law to individual prudence inquiries would likely prove a daunting, though perhaps not impossible task. Although the general picture of the law during the MGP era is clear enough, the law was not static. Attempting to say what legal nuance or subtlety applied when MGP wastes were generated or disposed of or when contaminants may have crossed a site boundary resulting in nuisance injury (assuming such dates could be established) would be difficult, indeed (Tr. XVI, pp. 103-04).

The generic investigation in this docket also persuades us that site-specific information from contemporaneous records is likely to be fragmentary and enigmatic. Mounting a case, whether for prudence or imprudence, would probably prove, at best, extremely difficult in any case. Serious expense would be entailed on the part of the gas companies, the Attorney General, and the Department without significant likelihood of greater benefit to ratepayers in comparison with the outcome under the Settlement Agreement. Because of the inevitable hazards attendant on recordskeeping by corporate predecessors of today's gas companies, inconsistency and unfairness may result in developing a case-by-case body of MGP prudence precedent. Cases might well be decided by the chance survival or perishing of records from decades or even a century and a half ago. In addition, translating an MGP plant operator's incurrence of risk of strict liability into imprudence, while not an impossible task, requires a nicety of judgment that is certainly open to good faith disagreement.

In contrast to all these uncertainties is the clear-cut sharing of cost and risk set forth in the Settlement Agreement. Applying the law of the MGP era might, in fact, favor recovery where hazardous materials from the MGP industry have not migrated from MGP plant sites or lawful dumpsites. While investigation of Massachusetts MGP sites has not progressed to a state of detailed assessment, the nature of the wastes is such that risk of migration offsite appears to be small or moderate (Tr. XVI, p. 38). For these reasons, we conclude that the Settlement Agreement represents a reasonable allocation of costs between shareholders and ratepayers.

C. Insurance Coverage, Litigation, and Proceeds

Massachusetts law concerning insurance coverage of MGP waste cleanup is presently inchoate at best. Some preliminary steps are being taken, to be sure, that may answer certain questions. For example, the Federal court for the Massachusetts District has certified certain questions of insurance law to the Supreme Judicial Court regarding coverage for the cleanup of New Bedford harbor. In Re Acushnet River & New Bedford Harbor Proceedings, 725 F.Supp. 1264 (D. Mass. 1989). In addition, the Supreme Judicial Court has before it an appeal on kindred issues in Hazen Paper Co. v. United States Fidelity & Guaranty Co., Hampden County Super. Ct., Civil Action No. 86-1679 (January 10, 1989).

Whether and how the Court may pronounce on these issues is not known, and the absoluteness of any resolution it offers is not certain. And, even were the Court to answer all the legal questions now before it, much time and effort would be expended to apply its answers to insurance litigation over the scores of MGP sites across the Commonwealth.[12] Thus, whatever the upshot of the two matters now before the Court, insurers are certain to show their customary energy and adeptness in asserting their defenses and in taking years to do so (Tr. I, p. 69, ll. 19-24). Against this background, we have assessed the insurance provisions of the Settlement Agreement.

Early in hearings, the Department expressed concern lest allowing rate recovery of all or a major part of MGP cleanup costs, as urged by the gas company petitioners on brief, would

12 Moreover, one of the most contentious issues is not before the Court in either of these cases: namely, the application of the "owned property" exclusion in standard policies on MGP sites owned by the gas company petitioners or their predecessors (Tr. II, p. 120; Attorney General Brief, pp. 141-42). The "owned property" exclusion, a typical feature of general liability insurance policies, states that the policy does not apply to damage to property owned or occupied by the insured, as, for example, an MGP plant site itself (Exh. CO-1, p. 33). Some courts apparently are disposed to construe such clauses against the insurer. Allstate Insurance Co. v. Quinn Construction Co., 713 F. Supp. 35 (D. Mass. 1989); C.K. Smith & Co. v. American Empire Surplus Lines, Inc., Worcester County Super. Ct., Civil Action No. 85-32950 (September 27, 1989). But the Supreme Judicial Court apparently has not yet spoken on point.

eliminate "a powerful incentive on the part of the companies to press their claims against their insurance companies" (Tr. II, p. 122). Section VI of the Settlement Agreement recognizes and accomodates this concern. It provides that half of any recovery against insurers or other PRPs would be retained by the gas company so recovering, while the other half would be returned to ratepayers, with adjustment for expenses for prosecuting the claim. This provision allays the Department's concern that any scheme for rate treatment, put into effect before insurance law is clarified and claims are pursued to a conclusion, must maintain a strong incentive for gas companies to assert their policy rights vigorously.

D. <u>Ratemaking Treatment of MGP Waste Cleanup Under the Settlement Agreement</u>

The terms of the Settlement Agreement are dispositive of the critical ratemaking issues that have been reviewed in this investigation. In particular, the Settlement Agreement would resolve, <u>inter alia</u>, the following matters that have received attention in this case: (1) the class of expenses they represent (<u>e.g.</u>, whether extraordinary or nonextraordinary, recurring or nonrecurring); (2) whether the costs are recoverable through base rates or an external, mechanism similar in operation to the CGAC; and (3) the treatment of deferred remediation costs with regard to interest accrual. To establish that the Settlement Agreement, in fact, provides a reasonable outcome in disposing of these issues with the Settling Parties, a brief review of existing Department precedent is useful.

The Department has traditionally broken down utility expenses into four categories: (1) annually recurring expenses; (2) periodically recurring expenses; (3) nonrecurring expenses that are extraordinary in amount or nature; and (4) nonrecurring expenses that are not extraordinary in amount or nature. Fitchburg Gas & Electric Light Company, D.P.U. 1270-1414, pp. 32-33 (1983). The Department typically allows annually recurring expenses and normalized values of periodically recurring expenses to be included in a company's cost of service. The Department also allows recovery of extraordinary nonrecurring expenses through amortization and collection from ratepayers over an appropriate period of time.

Following the decision in Commonwealth Electric Company, D.P.U. 88-135/151 (1988), in which the Department disallowed certain costs associated with hurricane damage because the expenses were incurred before the test year, several gas companies presented the Department with petitions to defer environmental cleanup costs for future ratemaking consideration. In response to these petitions, the Department has granted deferral accounting for cleanup costs for several companies: Colonial, Bay State, Boston Gas, and Berkshire. In granting deferral accounting, the Department noted that the sole ratemaking implication of deferral is to remove, as an impediment to ratemaking consideration, the fact that the expenditures were made before the test year that serves as the basis for a general rate proceeding. Interlocutory Order, p. 18

n. 4; Colonial Gas Company, D.P.U. 89-170 (1989); Boston Gas Company, D.P.U. 89-177 (1989); Bay State Gas Company, D.P.U. 89-81, Interlocutory Order (1989).

The Department noted in Colonial Gas, D.P.U. 89-70, that cleanup expenses relating to manufactured gas wastes can reasonably be predicted to recur over the next several years. Unlike rent, wages, or other periodically recurring expenses, it is not possible to derive a representative level of cost for MGP cleanup activities because the precise amount of the expense and its periodicity are subject to significant uncertainties, largely outside of the direct control of the companies. The Department also noted in Colonial Gas that environmental cleanup activities relating to MGP wastes have attributes of both recurring and nonrecurring expenses. Id., p. 7.

In the present generic investigation, there is little controversy on the record that the level of MGP remediation costs expected for the industry as a whole in the Commonwealth will be extraordinary in nature or amount. However, the Settlement Agreement makes no pronouncement on this issue. In creating a separate accounting mechanism to facilitate recovery of remediation costs as a separate cost item, the Settlement Agreement appears to accommodate and facilitate what in all likelihood become an extraordinary cost over time for the gas distribution industry as a whole.

The seven-year amortization of remediation expenses, without interest, appears to reflect a ratemaking treatment that the Department generally permits for extraordinary, nonrecurring costs. In amortizing extraordinary nonrecurring expenses, the Department has typically found an amortization period of between three and five years, with as long a period of ten years, to be appropriate, depending on the particular circumstances of the case. As a general practice, the Department does not allow carrying charges to accrue on unamortized balances of extraordinary costs. The Department finds that the proposed amortization of remediation expenses in the Settlement is not inconsistent with the body of Department rate case precedent, or with the record in this case. The Settlement Agreement's amortization approach provides a reasonable result for ratepayers and gas companies alike.

At a meeting with the Department on May 2, 1990, the Settling Parties provided the Department with a spreadsheet that depicts the operation of the environmental response cost recovery mechanism and the relationship of nominal costs and "real" costs recovered, given an assumed discount rate (Exh. DPU-33). The spreadsheet indicates that this mechanism would recover between approximately 43 percent and 50 percent of the present value of the remediation expenditures incurred by the gas companies, at discount rates of 15 percent and 11 percent, respectively. While the example is a fairly simple case, the Settling Parties provided it to demonstrate to the Department, in general terms, the effect it would have on consumers. The spreadsheet exhibit (Exh. DPU-33) reinforces our view that the Settlement Agreement establishes an equitable basis for allowing gas companies to recover MGP remediation costs.

E. Additional Considerations

Several features of the Settlement Agreement add to its value for the Settling Parties and for the Department. One essential benefit of the Settlement Agreement is that for the Companies, even though the real dollar recovery of Environmental Response Costs is significantly discounted, the Settlement Agreement will dispel much of the uncertainty in the financial community about the fiscal consequence of these costs for gas companies (Exh. CO-19, pp. 21-22). From an accounting standpoint, the Settling Parties indicated that adoption of the settlement would provide a more certain basis upon which accountants and financial analysts could evaluate gas company finances in contrast to the presently uncertain climate. It is frequently observed, of course, that financial uncertainty may translate into higher capital and borrowing costs for a utility and that, sooner or later, these costs may be borne by ratepayers (id., pp. 11-12). The clarity that the Settlement Agreement affords should help to assuage the concerns of the financial markets and thereby serve to reduce borrowing costs.

The Settlement Agreement would essentially preclude the Settling Parties from litigating the prudence of pre-1979 manufactured gas operations, and waste disposal and decommissioning activities that resulted in the need to incur Environmental Response Costs. From an administrative perspective, the Settlement Agreement would greatly reduce the extent of litigation surrounding MGP issues in rate cases or other proceedings. In recent rate case filings that preceded the Settlement Agreement's filing, the MGP issues resolved by the Settlement Agreement required lengthy and exhaustive reviews that and posed further administrative burdens in reviewing rate case filings in the already constrained, six-month statutory time-limit. Thus, the Settlement Agreement not only provides a satisfactory and fair ratemaking outcome for MGP for both gas customers and the gas companies, but it does so in an efficient manner.

The Settlement also provides certain public policy benefits that, while not directly affecting ratepayers, are of general concern to the communities affected by MGP waste issues. It is apparent that the gas company petitioners' full and cooperative participation in complying with the spirit and letter of the law in remediating former MGP sites is enhanced by the certainty of ratemaking treatment established by our approval of the Settlement Agreement. By permitting cost recovery in an agreed-upon manner, the Department fully expects that gas companies will proceed to carry out their environmental responsibilities both in a cost-effective manner for ratepayers and in a cooperative fashion with environmental agencies. Uncertainty over ratemaking treatment is no longer an impediment to meeting the goals of environmental cleanup.

F. Conclusion

The Department finds that the Settlement Agreement establishes a reasonable ratemaking mechanism for dealing with environmental response costs that have been or may be incurred by the gas company petitioners. Accordingly, upon the foregoing considerations and analysis, the Department finds that granting the Joint Motion and approving the Settlement Agreement are in the public interest.

VI. ORDER

Accordingly, after due notice, hearing, and consideration, it is

ORDERED: That the Joint Motion of the Settling Parties be and hereby is allowed; and it is

FURTHER ORDERED: That the Settlement Agreement submitted by the Settling Parties be and hereby is approved as providing a fair and equitable resolution to the matters in controversy in the proceedings docketed as D.P.U. 89-161; and it is

FURTHER ORDERED: That the proceedings docketed as D.P.U. 89-161 be terminated with findings that in light of the terms and conditions of the Settlement Agreement, no further investigations are required and that the Department will not on its own motion in the future institute an investigation concerning the prudence of the conduct that resulted in the need to incur Environmental Response Costs as well as the ratemaking treatment, if any, to be accorded Environmental Response Costs.

By Order of the Department,

/s/ BERNICE K. McINTYRE

Bernice K. McIntyre, Chairman

/s/ ROBERT N. WERLIN

Robert N. Werlin, Commissioner

/s/ SUSAN F. TIERNEY

Susan F. Tierney, Commissioner

A true copy
Attest;

MARY L. COTTRELL
Secretary

Appeal as to matters of law from any final decision, order or ruling of the Commission may be taken to the Supreme Judicial Court by an aggrieved party in interest by the filing of a written petition praying that the Order of the Commission be modified or set aside in whole or in part.

Such petition for appeal shall be filed with the Secretary of the Commission within twenty days after the date of service of the decision, Order or ruling of the Commission, or within such further time as to the Commission may allow upon request filed prior to the expiration of the twenty days after the date of service of said decision, Order or ruling. Within ten days after such petition has been filed, the appealing party shall enter the appeal in the Supreme Judicial Court sitting in Suffolk County by filing a copy thereof with the Clerk of said court. (G.L. Ter. Ed.,c. 25, s. 5, as most recently amended by c. 485 of the Acts of 1971)

MISSOURI GAS ENERGY
A Division of Southern Union Company

MISSOURI GAS ENERGY
DATA INFORMATION REQUEST
Missouri Rate Case No: GR-2004-0209
Data Request No: 0130

Requested From: Tom Imhoff

Date Requested: 4/23/04

Information Requested:

Has witness Imhoff, or any other individual or individuals on the Commission Staff, undertaken any analysis to ascertain how any changes proposed to Section 3.02 will affect the costs MGE incurs for its collection process? If so, please provide the results of that analysis and any information or material upon which it is based.

Requested By: Michael R. Noack

Information Provided:

No.

Date Response Received:__________

Signed By: Tom Imhoff

Date: 5/12/04

Schedule MRN-5

Missouri Gas Energy
COMPARISON OF ACHIEVED RATE OF RETURN
VS. AUTHORIZED RATE OF RETURN

Description	6/30/1996 (000)	6/30/1997 (000)	6/30/1998 (000)	6/30/1999 (000)	6/30/2000 (000)	6/30/2001 (000)	6/30/2002 (000)	6/30/2003 (000)	Cumulative (000)
Net Operating Income	$ 30,821	$ 30,056	$ 32,785	$ 35,566	$ 31,624	$ 33,582	$ 39,984	$ 37,421	
Net plant from most recent rate case	$ 359,290	$ 359,290	$ 431,152	$ 431,152	$ 431,152	$ 431,152	$ 503,192	$ 503,192	
Net Plant Balance at 6/30/XX	360,288	384,986	440,251	460,145	478,794	491,271	505,412	525,495	
Increase in plant since most recent rate case (includes average current year plant additions	$ 499	$ 13,347	$ 4,550	$ 19,046	$ 38,318	$ 53,881	$ 1,110	$ 12,262	
Estimated increase in deferred taxes	$ (614)	$ (7,367)	$ (2,728)	$ (8,183)	$ (13,638)	$ (18,632)	$ (6,800)	$ (11,333)	
Total rate base from most recent case updated for annual plant increases	$ 347,927	$ 354,022	$ 420,041	$ 429,082	$ 442,899	$ 453,468	$ 496,740	$ 503,359	
Achieved Rate of Return	8.86%	8.49%	7.81%	8.29%	7.14%	7.41%	8.05%	7.43%	
Authorized Rate of Return	10.54%	9.46%	9.46%	9.40%	9.40%	9.40%	9.03%	9.03%	
Date Rates Went into Effect	1-Feb-94	1-Feb-97		2-Sep-98			6-Aug-01	6-Aug-01	
Return Deficiency	-1.68%	-0.97%	-1.65%	-1.11%	-2.26%	-1.99%	-0.98%	-1.60%	
Earnings Deficiency	$ (5,851)	$ (3,434)	$ (6,951)	$ (4,768)	$ (10,009)	$ (9,044)	$ (4,872)	$ (8,032)	$ (52,960)
Revenue Deficiency	$ (9,531)	$ (5,594)	$ (11,323)	$ (7,766)	$ (16,303)	$ (14,732)	$ (7,936)	$ (13,083)	$ (86,266)

* - High end of Staff recommendation implicit in the settlement