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

6th Revised Sheet Nos. 3.1, 6.1, and 9

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

5th 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

121st Revised Sheet No. 9a

19th Revised Sheet No. 9b

140th 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

_J 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

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)

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[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

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. Earnings Sharing Calculation

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. <u>Burden of Proof</u>

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.

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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