STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

PUBLIC UTILITIES COMMISSION

Providence Gas Company	)	Docket No. 2581

SETTLEMENT AGREEMENT

The Providence Gas Company ("ProvGas" or the "Company"), the Division of Public Utilities and Carriers (the "Division"), The Energy Council of Rhode Island ("TEC-RI") and The George Wiley Center (together, the "Settling Parties") have reached agreement on terms for a 21-month extension of the Price Stabilization Plan ("PSP"). The negotiated extension includes certain modifications to reflect changes in the Company's costs of service since the commencement of the PSP, approved by the Rhode Island Public Utilities Commission (the "Commission") in August 1997. The negotiated changes to the PSP and the reasons for the term of the negotiated extension are detailed herein. This Agreement is intended to supercede and replace the terms of the existing PSP as of October 1, 2000.

The Settling Parties thus agree to seek approval of this Agreement by the Commission. The Agreement recognizes the need for an increase in distribution system revenues of $4.5 million, recovered through an adjustment to the throughput portion of the gas charge, similar to what occurred in the original PSP Agreement in Docket No. 2581. The increase in distribution system revenues reflects revenue requirement increases since 1997. The Agreement provides for a base rate freeze through at least June 30, 2002,

incorporates a decrease in the fixed component of gas costs of $9.0 million annually, and provides for an increase in the throughput charge of 5%, the revenues of which will be credited to firm customers as an addition to the fixed gas credit. Other elements of the Settlement include a continuation of the Low-Income programs through the heating seasons of 2000/2001 and 2001/2002, certain investment commitments on the Company's part, resolution of outstanding claims for recovery of Exogenous Changes, including full recovery of amounts included in the Deferred Revenue Account on September 30, 2000 and waiver of claim of any Exogenous Changes for 1999 and 2000 under the current PSP, introduction of a weather mitigation clause and a modification to the treatment of the non-firm gas margins. Such modification removes non-firm margins from any future exogenous claim, reducing the present risk to firm customers, and gives the Company an incentive to maximize sales to non-firm customers to the benefit of the Company and its customers.

I. PREAMBLE

A. Introduction:

The PSP, introduced in 1997 as an agreement among the Settling Parties, addressed a number of key issues facing the Company and its customers at that time. First and foremost, the PSP was designed to offer assurances of price stability and service reliability during a period of regulatory transition and adjustment to new market structures. The PSP achieved these objectives while committing the Company to expand the capacity

and reach of its natural gas distribution system in order to help promote the State's economic development initiatives.

Now as we approach the end of the three-year term of the PSP, the Parties seek an extension of certain components of the PSP, with modifications, to facilitate the transition between the current PSP and the establishment of Company operations in the post-Southern Union merger period. On November 15, 1999, Providence Energy Corporation ("ProvEnergy") and Southern Union Company entered into an Agreement and Plan of Merger for the merger of ProvEnergy, and its principal operating subsidiary, ProvGas, with and into Southern Union. While it was anticipated that some modification to the PSP would be required at the end of its initial three-year term, recent price volatility in the gas markets and the Company's pending merger have necessitated additional program considerations.

Foremost among these considerations is recognition of the consolidation of ProvGas and Valley Gas under common Southern Union ownership. A unanimous settlement of all merger-related issues has been approved by the Division Administrator in Division Docket Nos. D-002 and D-003. That settlement requires the preparation and filing of consolidation proposals and a rate plan within a time frame that would produce new rates for the Company at the end of the period that this 21-month PSP extension addresses. With that consolidation, a comprehensive review of the Company's rates and operations is anticipated. Accordingly, it is apparent that all parties would be best served by extending the PSP in order to bridge the time period until a rate plan for the

consolidated companies can be implemented. The 21-month extension of the PSP set forth in this Agreement accomplishes that objective.

A second consideration is the change in gas market conditions. Prices for gas supply have increased significantly in recent months and those increases in gas commodity prices indicate that adjustment of the commodity price under the current PSP will be necessary. On the other hand, the Company has negotiated a new rate for its pipeline demand charges which is lower than that which it currently pays for such service under the existing PSP. Since the Company's fixed gas supply rate has been established, these costs will be recovered through that portion of gas costs included in base rates. Only the gas commodity costs will be subject to the traditional GCC recovery treatment during the term of this Agreement.

With respect to the throughput rate adjustment, it has been established that, at the end of the PSP's three-year term, there is a need to adjust revenues to reflect cost increases and additional investment made during the duration of the initial PSP. While adhering to the underlying concepts of the PSP, a limited throughput rate increase is necessary to achieve an additional 21-month base rate freeze. The amount of the increase, which is discussed in the Terms of Settlement section of this Agreement, was subject to full review and analysis by the Settling Parties. Moreover, the Company's achieved return on common equity during the 21-month PSP extension continues to be capped so as not to exceed 10.9%. Any return that the Company achieves in excess of 10.9%, with the exception of the Company's share of non-firm margin sharing, discussed further below, will be credited to the benefit of ratepayers.

B. Parties' Statement:

This Settlement Agreement is based on extensive discovery and negotiations among the Settling Parties concerning all aspects of the PSP, the pending merger, and natural gas market conditions. The Settling Parties do not necessarily agree on every item of the Settlement; however, the Settling Parties agree that the outcome of this Settlement Agreement, as a whole, is just and reasonable. This Settlement Agreement does not address all of the issues related to the commodity cost component of the GCC, as discussed below.

II. TERMS OF SETTLEMENT

A. Scope:

The Settlement Agreement would establish retail gas-service rates for the Company's residential, commercial and industrial customers, while committing the Company to continued infrastructure investment and support of low-income and DSM programs as described below.

B. Term:

The term of this proposal is 21 months, commencing on October 1, 2000 and continuing through June 30, 2002 (the "Extended Term").

C. Extended Term Base-Rate Freeze:

The Company will, subject to the terms of this Agreement, commit to a base-rate freeze for the 21 months of the Extended Term. In addition, following an initial adjustment, the throughput portion of the Gas Charge shall be frozen for the duration of the Extended Term, subject only to a potential adjustment based on changes in the LNG

commodity portion of the throughput component. The Company shall not seek a base rate increase to take effect prior to the close of the Extended Term. The Settling Parties agree that the Company will recover additional capital investments and operating and maintenance expenses that support the safety, reliability and integrity of the Company's distribution system through the Company's retention of a portion of the annual savings in fixed gas costs of $0.475 per MMBtu and increases of 5% in the throughput component of the GCC. Such decreases in fixed gas costs and increases in throughput revenues respectively equal approximately $9.0 million and $0.5 million annually.

In addition, under the terms of the Settlement Agreement in Division Docket No. D-00-003, the Company's pending merger with Southern Union Gas Company, requires the Company to file with the Commission no later than December 1, 2001 a rate plan as well as a detailed consolidation plan that will evaluate consolidating various operational and support activities. The Company shall attempt to make such filing by November 1, 2001.

D. Rate Changes:

1. Gas Charge Clause:

The Gas Charge Clause ("GCC") shall be modified as follows: (1) to reestablish the mechanism that enables the Company to adjust prospectively the current GCC rate applicable to sales service customers based on commodity costs approved in the Company's GCC proceedings; and (2) to increase and then freeze the throughput component of the GCC, subject only to a potential adjustment based on changes in the

LNG commodity portion of the throughput component. Attachment 1 is a copy of the tariff modifications.

During the Extended Term, the effective GCC rate will be the combination of the current GCC rate, which is $1.283 per Mcf for Residential and Small C&I customers and $5.624 per Mcf for Medium and Large C&I customers, and an adjustment to reflect changes in commodity costs to be approved in the Company's GCC proceedings. During the Extended Term the proposed Commodity Cost Adjustment Factor will be the mechanism used to isolate GCC commodity prices, and to adjust the GCC rates based on those prices relative to the commodity prices underlying a GCC rate of $2.568 per MMBtu. Specifically, as part of the September 2000 GCC annual filing, the Company will file its projection of commodity costs in accordance with Section 2 of the Company's tariff, Schedule A, Item 11.0, subject to review and approval by the Commission. Such costs will include all commodity-related costs, and exclude pipeline and underground storage demand charges (i.e., those costs included in the Fixed Basis Price of the Supply and Asset Management Agreement). The adjustment to commodity costs will also reflect a fixed cost credit of $6.2 million, $3.7 million in the first twelve (12) months and $2.5 million in the next nine (9) months as shown on Attachment 2. In subsequent filings, such forecasts will include any reconciliation amount, representing the difference between actual commodity costs and projected GCC commodity costs.

The Throughput Component of the Gas Charge shall be increased by 5% and then frozen for 21 months at the levels set forth in Attachment 3, subject only to a change in the LNG commodity portion of the throughput charge. The LNG commodity cost included in

the current throughput charge is $0.045 per Mcf; however, given the potential volatility of commodity costs over the next 21 months, the Settling Parties agree to recalculate the LNG commodity portion of the throughput charge as part of the FY2002 GCC proceeding. If such recalculation results in an increase of more than $0.005 per Mcf, then the throughput charge shall be increased by such amount over $0.005 per Mcf. If such recalculation results in a decrease of more than $0.005 per Mcf, then the throughput charge shall be decreased by such amount over $0.005 per Mcf.

E. Investment Commitments:

The Company commits to specific capital investments that enhance the safety, reliability and integrity of the distribution system. Such investments are as follows:

1. The Company commits to continue its program of cast-iron and bare-steel mains and services replacement. Such commitment does not include reimbursed replacements associated with local, state, or federal construction projects. Such replacement shall average approximately seven miles per year which is one mile per month during the construction season of April through October, or 11.0 miles of main over the 21 month settlement period. In addition, the Company will commit, on a best efforts basis, to replace an average of 10 miles of main per year or 15.7 miles of main over the 21 month settlement period.
2. The Company commits to complete its review, update and consolidation of its mains and services records, replacing a basically

paper file system having records dating as far back as 1874. Completion of this project will include: (1) development of electronic landbase maps; (2) preparation, scrubbing, and updating of facility records; and (3) coding facility records in an electronic format, including consolidation of installation and maintenance records for mains and services. The Company agrees to provide the Division with a status report for this project on a semi-annual basis during the Extended Term.

3. The Company commits, subject to the requisite regulatory approvals of its proposed project, to provide additional capacity on Aquidneck Island that will provide additional gas service to customers in Newport, Middletown and Portsmouth.

F. Low Income and Demand-Side Management Commitments:

The Company proposes to continue funding of the following programs:

1. The Low Income Assistance Program will be funded at an annual level of $1.3 million for each year of the Extended Term.
2. The Demand Side Management rebate program will be funded at an annual level of $0.3 million. The Company agrees to work with the Settling Parties on simplifying the administrative requirements of the current program.
3. The Low Income Weatherization Program will be funded at an annual level of $0.3 million for the first year and $0.2 million for the second

year. Such funds shall include unused funding for the Low Income Assistance Program under the existing Agreement that expires on October 1, 2000. The Settling Parties agree to attempt to identify additional funds for the Low Income Weatherization Program in the second year.

G. Accounting Treatments:

1. Environmental Response Fund:

An Environmental Response Fund shall be established to create a mechanism to fund the recovery of "Environmental Response Costs" as defined below.

(a) Definition of "Environmental Response Costs". "Environmental Response Costs" are all the reasonable and prudently incurred costs associated with evaluation, remedial and clean-up obligations of Providence Gas Company arising out of the Company's utility-related ownership and/or operation of: (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 include costs of acquiring property associated with the clean up of such sites as well as litigation costs, claims, judgments, and settlements associated with such sites. 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. Any applicable insurance proceeds net of costs associated with obtaining such proceeds shall be credited to the fund. To the extent the Company incurs any other environmental liability of which it is not aware as of the date of this Settlement, the Company has the right to defer and then request in a subsequent proceeding that the Commission allow such costs incurred in connection with such liability to be included as "Environmental Response Costs".

(b) Funding. Interest shall accrue, for the benefit of customers, on any credit balances in the fund at the customer deposit rate. No interest shall accrue on debit balances. Any cash expenditures shall be charged to the fund as long as the costs that are incurred or previously deferred are Environmental Response Costs, as defined above. The fund shall be credited at the annual amount of $678,282 (the current amount reflected in rates for amortization of such costs) or $56,524 per month.

(c) Annual Reports. Providence Gas Company will file an annual report with the Commission (and serve the Parties with copies) providing a summary and accounting of all costs incurred during such year which have been applied to the fund. A separate account

will be maintained on the Company's books for accruals and expenditures for environmental response costs. Each of the Parties reserve their rights to review and challenge any costs that they believe do not fall within the definition of "Environmental Response Costs", as defined in subparagraph (a) above.

(d) Reservation of Rights. In the Company's first COS rate case to establish rates after the expiration of this Agreement, all Parties to this Settlement reserve their rights to take any position they deem appropriate regarding (i) the level of funding to be permitted in rates on a prospective basis to recover costs charged to the fund as of the date of such case, and/or (ii) whether the fund should continue as designed in this Settlement for the recovery of prospective costs.

2. Year 2000 Amortization:

The Company will adopt a 15-year amortization period for Year 2000 (Y2K) costs unamortized as of September 30, 2000 (projected September 30, 2000 balance of $6.9 million). The 15 year amortization period of such unamortized costs shall begin in October 2000.

3. Unamortized CIS System:

The Company will remove from its calculation of rate base the unamortized portion of its legacy CIS system but will include the amortization of the unamortized balance in its Cost of Service

(projected September 30, 2000 balance of $2.3 million) as part of its Y2K costs referred to in Section II.G.2. The new CIS system is being amortized over a period of 18 years beginning in October 1999.

H. Interest on Customer Deposits:

The Company will implement an interest rate on customer deposits equal to the rate paid on ten year, United States Treasury bonds for the preceding calendar year.

I. Earnings Reports:

1. Deferred Revenue Account ("DRA"):

The Company will establish a Deferred Revenue Account during the Term of the Agreement. Such account shall be used in accordance with the various provisions of this Agreement and maintained on a pre-tax basis. Any resulting positive or negative DRA balance at the end of the Extended Term shall then be credited or debited to customers, respectively, in a manner determined by the Commission.

2. Calculation of Return on Equity:

The determination of whether the Company has exceeded its allowed rate of return on equity will be made at the end of the Extended Term. Specifically, the Company shall file an earnings report with the Commission calculating the return on equity for the Extended Term using an average of the return on equity for the 2 twelve-month reporting periods: October 1, 2000 – September 30, 2001; and July 1, 2001 – June 30, 2002. These periods will enable the Company to accurately report earnings without distortion from the seasonal nature of the Company's earnings. For the purpose of such earnings report, the allowed return on equity shall be 10.9 percent, excluding the Company's portion of non-

firm margin as addressed in Section K. Results will be adjusted to reflect established Commission ratemaking principles, including the impact of the Weather Mitigation Clause, as discussed below. However, there will be no adjustments 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, or the level calculated pursuant to Section II.I.2 times the applicable cost rate, and the applicable preferred dividends, if any, 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 at the end of each reporting period referred to in Section II.I and established Commission ratemaking principles. The working capital allowance will be calculated pursuant to the method approved by the Commission in Docket No. 2286, utilizing most recent data.

Any earnings in excess of 10.9 percent, excluding the Company's incentive portion of non-firm margins, shall be credited to the DRA. Any earnings less than 7 percent,

excluding the Company's incentive portion of non-firm margins shall be debited against the DRA through the deferral of costs.

3. Capital Structure:

The Company shall use the actual capital structure and associated costs of capital in determining its earned return on equity, as described in Paragraph 1. However, the Company's actual level of equity and total capital for financial accounting purposes will be affected by the pending merger with Southern Union. Therefore, if ProvGas' actual average common equity ratio is above 50% for any reporting period during the Extended Term, then the Company shall use a capital structure consisting of 50% debt and 50% equity.

4. Operations and Maintenance (O&M) Expenses:

To calculate O&M expense limitations for determination of whether the Company has exceeded its allowed rate of return on equity, the Company shall utilize actual non-gas O&M expenses for the applicable reporting periods referred to in Section II.I, in accordance with the FERC Form No. 2; provided that such O&M expenses do not exceed an annual threshold based on eighty-five percent (85%) of the annual increase in the simple average of the Consumer Price Index (CPI) and Gross Domestic Product – Producer Index (GDP-PI) compounded from the FY96 base of $46.5 million. The Settling Parties recognize, however, that unforeseen exogenous events which are beyond the Company's reasonable control, such as severe colder-than-normal weather, severely adverse economic conditions, significantly increased health care costs, significantly increased bad debt expense, changes in the tax laws or tax rates (federal, state or local),

mandatory changes in generally accepted accounting principles (GAAP) or current interpretations of GAAP as applied to the Company (i.e., the continued applicability of FAS 71 to the Company), changes in definition and/or calculation of CPI and GDP-PI, and regulatory, judicial, or legislative changes affecting the Company's costs, may cause the Company to exceed such threshold and that, under such circumstances, the Company shall calculate ROE utilizing actual non-gas O&M expenses. If a dispute arises over whether any event(s) is exogenous within the meaning of this provision, the burden of proof lies with the Company to demonstrate that the event was exogenous and had a significant impact on the Company's O&M expenses. Upon written request by the Division, the Company will provide the Division with all relevant information in its possession regarding any such change sought by the Company. Any disputes shall be resolved by the Commission.

J. Exogenous Events:

Independent of other provisions included in the Agreement, the Company shall be permitted to account for in the DRA the impact of Exogenous Events as described herein.

1. Exogenous Events are significant increases or decreases in the Company's revenue requirement that are beyond the Company's reasonable control, and shall be limited to the following:

   a. <u>State Initiated Exogenous Change</u>: For purposes of this Settlement, the term "State Initiated Exogenous Change" shall mean a change in ProvGas' revenue requirements by more than $250,000 resulting from:

(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 revaluations);

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

(iii) any state legislative or state regulatory mandates which impose new obligations, duties, or undertakings, or remove existing obligations, duties, or undertakings which individually decrease or increase ProvGas' revenue requirement.

b. Federally Initiated Exogenous Change: For purposes of this Settlement, the term "Federally Initiated Exogenous Change" shall mean a change in ProvGas' revenue requirements by more than $250,000 resulting from:

(i) any externally imposed changes in the federal tax rates, laws, regulations, or precedents (including new standards issued by the Financial Accounting Standards Board) governing income, revenue, or sales taxes or any changes in federally imposed fees; and

(ii) any federal legislative or federal regulatory mandates which impose new obligations, duties or undertakings, or remove existing

obligations, duties, or undertakings which individually decrease or increase ProvGas' revenue requirement.

2. The Settling Parties agree that this Agreement provides for recovery of FY1998 Exogenous Events, and also waives claims of FY1999 and FY2000 Exogenous Events, under the terms of the current Agreement.
3. Each Settling Party has the right to make a filing to open a proceeding if it believes an Exogenous Event has occurred; however, such exogenous event shall be limited to those items identified under Section J.1. above. If a dispute arises over whether a change is exogenous or to the quantification of such impact, the burden of proof lies with the Settling Party.
4. Excluded from exogenous treatment are revenue impacts due to severely abnormal weather and recovery of non-firm margins, subject to satisfactory agreement by the Settling Parties and filing to the Commission of a weather-normalization clause described in Section L below.
5. The Company will notify the Settling Parties as soon as practicable in advance of such claim for recovery of any Exogenous Events. Exogeneous Events shall be reviewed and approved by the Commission.
6. The impact of any Exogenous Events will be debited or credited to the DRA through the Extended Term.

K. Non-Firm Margins:

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

1. Seventy-five percent (75%) of all non-firm margins will represent the ratepayers' portion of non-firm margins. Twenty-five percent (25%) of all non-firm margins will represent the Company's portion of non-firm margin. Such portion will accrue to the Company and shall be excluded from the calculation of the Company's financial performance under Section I of this Agreement. The first $1.2 million of non-firm margins will accrue to the Company because the ratepayers' portion of such non-firm margins has been imputed in the proposed rates.
2. The Company will accrue 75% of non-firm margins that exceed $1.2 million until the end of the Extended Term, at which point the Company will credit the accumulated amount through the throughput component of the GCC.

L. Weather Mitigation Clause:

The Settling Parties agree that a weather mitigation clause is an appropriate mechanism to mitigate the impact of weather volatility on customer billings. The Settling Parties agree to develop and file such mechanism no later than 30 days from the filing of this Agreement for effect on October 1, 2000, which would be considered an unseverable

component of this Agreement. The Settling Parties also agree that such mechanism shall include a bandwidth of +/- 2%; thus, the Company will credit the DRA for the margin impact of weather that is greater than 2% colder-than-normal, and the Company will debit the DRA for the margin impact of weather that is greater than 2% warmer-than-normal.

M. Therm Billing Commitment:

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, resulting in no dollar impact on customers' bills. The Settling Parties agree to develop and file such mechanism on or before the expiration of this Agreement. In the meantime, the Settling Parties agree to develop and file no later than 30 days from the filing of this Agreement for effect on October 1, 2000 a mechanism that would reflect the impact of therm billing by adjusting for the difference between the actual heat content and the heat content underlying this Agreement.

N. Compressed Natural Gas ("CNG") Rate:

The Settling Parties agree that the Company shall adjust its Compressed Natural Gas rate by the Commodity Cost Adjustment Factor described in Section II.D.1 of this Agreement.

III. EFFECT OF SETTLEMENT AGREEMENT

This Agreement is the result of a negotiated settlement among the Settling Parties. The discussions which have produced this Settlement 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 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.

IN WITNESS WHEREOF, the parties agree that this Agreement is reasonable and have caused this document to be executed by their respective representatives, each being fully authorized to do so. Dated at Providence this 2nd day of August, 2000.

Respectfully submitted,

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By its Attorneys,

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GAS CHARGE CLAUSE

11.0 <u>MODIFICATIONS</u> Provisions in this Section are subject to modifications through June of 2002 as ordered by the Commission in approval of a Settlement Agreement on Energize RI in Docket No. 2581. Such modifications include the following:

(1) The Gas Charges under Item 3.0 of the Gas Charge Clause shall include all commodity-related costs and exclude pipeline and underground storage demand charges (i.e., those costs included in the Fixed Basis Price of the Supply and Asset Management Agreement. The Company shall file annually its commodity cost adjustment factor based on projected costs and sales volumes. Such projection shall be subject to reconciliation; thus, any overcollection or undercollection of costs shall be refunded to, or recovered from customers. The adjustment to commodity costs will also reflect a fixed cost credit of $6.2 million, $3.7 million in the first twelve (12) months and $2.5 million in the next nine (9) months; and

(2) The firm throughput cost component in Item 4.4 of the Gas Charge Clause shall be increased effective October 1, 2000. Such increase is related to substantial capital investments to support key economic development projects and maintain distribution system safety, reliability and integrity, as identified in the Price Stabilization Plan. Such firm throughput cost components are as follows:

(a)	Residential and C&I Small	$ 0.0818 per Ccf
(b)	C&I Medium and Large	$ 0.0522 per Ccf
(c)	C&I Extra Large Low Load	$ 0.0184 per Ccf
(d)	C&I Extra Large High Load	$. 0.0175 per Ccf

Derivation of Fixed Cost Credit
($ Million)

		2 Years	21 Months 95.72%
Increased Margin [1]		$19.05	
less: Revenue Requirements		($9.00)	
		$10.05	$9.62
less: DRA Balance[2]		($2.08)	($2.08)
		$7.97	$7.54
less: Non-Firm Adjustment		($1.40)	($1.34)
Total Fixed Cost Credit		$6.57	$6.20
Year 1	59.55%		$3.69
Year 2	40.45%		$2.51

[1] Consists of: Fixed gas cost savings of $18.0 million and
Increased transportation rates of $1.05 million over two years

[2] Includes:	GCC pre-ERI Underrecovery	($153,224)
	FY98 Exogenous	($2,450,000)
	Low Income Program	($200,000)
	DSM Balance (with State NGV)	$725,679
		($2,077,545)

Calculation of Throughput Factor Adjustment

	Current Throughput Rate (per Mcf)	Adjustment (per Mcf)	Adjusted Throughput Rate (per Mcf)
Residential Non-heating	$ 0.592	$ 0.226	$ 0.818
Residential Heating	$ 0.592	$ 0.226	$ 0.818
LLF Small	$ 0.592	$ 0.226	$ 0.818
HLF Small	$ 0.592	$ 0.226	$ 0.818
LLF Medium	$ 0.390	$ 0.132	$ 0.522
HLF Medium	$ 0.390	$ 0.132	$ 0.522
LLF Large	$ 0.390	$ 0.132	$ 0.522
HLF Large	$ 0.390	$ 0.132	$ 0.522
LLF Extra Large	$ 0.127	$ 0.057	$ 0.184
HLF Extra Large	$ 0.127	$ 0.048	$ 0.175

Calculation of Throughput Factor Increase

	Current Distribution Margin {1}	Volumes (Mcf) {1}	Average Margin	Current Throughput	Total Average Margin	5.00% Uniform Increase
Residential Non-heating	$ 5,137,038	610,757				
Residential Heating	$ 48,288,860	12,968,542				
LLF Small	$ 5,299,350	1,314,620				
HLF Small	$ 1,449,671	405,202				
	$ 60,174,919	15,299,121	$ 3.93	$ 0.592	$ 4.53	$ 0.226
LLF Medium	$ 6,390,540	2,407,003				
HLF Medium	$ 2,027,752	1,160,888				
LLF Large	$ 3,799,622	1,592,226				
HLF Large	$ 749,426	607,146				
	$ 12,967,340	5,767,263	$ 2.25	$ 0.390	$ 2.64	$ 0.132
LLF Extra Large	$ 612,264	605,349	$ 1.01	$ 0.127	$ 1.14	$ 0.057
HLF Extra Large	$ 289,099	349,623	$ 0.83	$ 0.127	$ 0.95	$ 0.048

{1} Docket No. 2374