STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
PUBLIC UTILITIES COMMISSION

IN RE: NEW ENGLAND GAS	:	
COMPANY'S RATE CONSOLIDATION	:	DOCKET NO. 3401
FILING	:	

REPORT AND ORDER

On November 1, 2001, the New England Gas Company ("NEGas"), a Division of the Southern Union Company ("Southern Union"), filed for a general rate increase and rate consolidation for the pre-merger entities of Providence Gas Company ("ProvGas") and Valley Gas Company and Bristol and Warren Gas Company ("Valley"). The increase in revenues was $7,219,413, or approximately 2.6%, for a combined cost of service of $271,530,711 to become effective December 1, 2001. The Rhode Island Public Utilities Commission ("Commission") suspended the rate application, and NEGas consented that new rates could go into effect by July 1, 2002.

During the course of the proceedings, the following parties filed motions to intervene: The Energy Council of Rhode Island ("TEC-RI"), the George Wiley Center, and Local No. 12431 of the United Steel Workers of America ("Local 12431"). There was no objection to the motions for intervention of TEC-RI and the George Wiley Center. The Commission granted Local 12431's motion to intervene over the objection of NEGas.[1]

I. NEGAS FILING

On November 1, 2001, NEGas submitted pre-filed testimony of Thomas Robillard, Sharon Partridge, Todd Craighead, John Quain, John Dunn, Christopher Gulick, David Heintz and Peter Czekanski. In his pre-filed testimony, Mr. Robillard, President of NEGas, provided an overview of the company's filing. Mr. Robillard indicated that NEGas' objectives are to provide safe, reliable and high quality gas service to its customers, to provide an adequate return to its shareholders, to maintain motivated employees, and to communicate effectively with the community.[2] To achieve these objectives, NEGas will consolidate the existing companies into a unified operation, successfully complete upcoming collective bargaining negotiations, be an active part of the community, and obtain approval of proposals that balance the needs of customers with NEGas' financial objectives.[3]

In her pre-filed testimony, Ms. Partridge, Vice-President of NEGas, discussed the proposed Rate Plan and its related revenue-requirements analysis. Ms. Partridge stated NEGas' goal of "One State, One Rate" was developed through the establishment of a unified revenue requirement. To develop the Rate Plan, Ms. Partridge established the pre-merger, stand-alone revenue requirement of each Rhode Island company. According to Ms. Partridge, absent the merger, the Rhode Island

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[1] Order No. 16925 (issued 2/25/02).
[2] NEGas Ex. 1: (Robillard's pre-filed testimony), p. 3.
[3] Id., pp. 4-5.

companies would have required a combined $9.5 million revenue increase or $5.6 million for ProvGas and $3.9 million for Valley.[4] The unified revenue requirements of NEGas are based on the financial results of the pre-merger Rhode Island companies for the last fiscal year of their stand alone operations, including adjustments for known and measurable changes occurring through June 30, 2003 and merger-related savings anticipated through June 30, 2005. Accordingly, NEGas calculated a combined revenue deficiency of $7.2 million.[5] The proposed revenue requirement is based on an overall 10.18 percent rate of return, and a 12.5 percent return on equity. Ms. Partridge argued that the merger tempered the amount of the revenue increase by nearly 25 percent, noting that Valley has not had a general rate increase in six years, and ProvGas' ERI I and ERI II "were stop gap settlements used to postpone full-fledged base-rate increases."[6]

Ms. Partridge stated that NEGas is proposing a simplified rate structure designed to eliminate confusion and combine the best practices of the existing rate schedules. In addition, NEGas is proposing to recover all gas costs through a revised gas-cost recovery charge ("GCRC") and recover demand-side management costs, low-income heating assistance,

[4] NEGas Ex. 2: (Partridge's pre-filed testimony), p. 4.
[5] Id., pp. 6-7.
[6] Id., pp. 8-9. See Order Nos. 16584 (issued 4/30/01) and 15548 (issued 3/6/98).

environmental response costs, the sharing of merger-related savings, and non-firm margin through a Distribution Adjustment Clause ("DAC").[7]

As for rate design, Ms. Partridge stated that to create a single rate structure for Rhode Island, there will be a relatively larger base-rate increase for Valley customers in comparison to ProvGas customers. Ms. Partridge argued that this approach is acceptable because Valley's base rates have not been increased for six years and the merger will benefit Valley customers from the implementation of information-systems technologies.[8]

To generate merger savings, NEGas will eliminate redundant job positions and implement common technology platforms. Ms. Partridge noted there are also merger-related costs such as corporate allocation costs from Southern Union. As a result, Ms. Partridge estimated net merger-related savings of $3,311,800 of which $827,900 has been included as an offset to NEGas' revenue increase.[9] In addition, NEGas proposed an earnings sharing mechanism ("ESM") whereby customers will receive 25 percent of the incremental earnings exceeding a return on equity ("ROE") of 12.5 percent but less than 15 percent, while incremental earnings exceeding 15 percent will be shared equally between customers and shareholders.[10] To prevent a diminishment of service due to NEGas' cost reduction measures, NEGas stated it is

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[7] Id., p. 9.
[8] Id., pp. 10-11.
[9] Id., pp. 11-13.

working with the Division to develop a service-quality measurement and monitoring program.[11] Finally, Ms. Partridge outlined the many pro forma adjustments to NEGas' rate years and concluded that the combined rate base was $271,102,396.[12]

Todd Craighead, consultant for NEGas, provided pre-filed testimony on savings expected from the merged companies. Mr. Craighead stated that by the end of Fiscal Year 2006, NEGas will achieve gross merger-related savings of approximately $13.1 million per year. Mr. Craighead noted that NEGas has already achieved gross on-going savings of approximately $2.96 million per year. In addition, he projected that realizing the total annual savings will require an approximate one-time expense of $3.41 million in total O&M costs and a one-time expense of $21.46 million in capital expenditures.[13]

Mr. Craighead grouped NEGas' functions into four categories: administrative services, customer services, field operations and gas supply. Mr. Craighead estimated that of the estimated annual savings of $13.1 million, the total labor savings are projected to represent approximately $11.4 million due to elimination of 112 positions.[14] In administrative services, NEGas proposed the elimination of 43 positions with a total O&M cost reduction of $5,210,423 and total projected one-

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[10] Id., pp. 13-14.
[11] Id., pp. 13-14.
[12] Id., p. 17.
[13] NEGas Ex. 4: (Craighead's pre-filed testimony), pp. 4-5.
[14] Id., pp. 15-16.

time capital costs of $1,960,000 and total projected one time O&M costs of $861,369.[15] In customer services, NEGas proposed the elimination of 35 positions with a total O&M cost reduction of $3,512,094 and total projected one-time capital costs of $12,713,000 and total projected one-time O&M costs of $1,722,622.[16] The one-time capital costs include the implementation of the Banner Billing and Customer Information System ("CIS") and Automated Meter Reading ("AMR") technology in the Valley service area.[17] In field operations, NEGas proposed the elimination of 27 positions with a total O&M cost reduction of $3,694,263, total projected one-time capital costs of $6,782,688 and total projected one-time O&M costs of $680,212.[18] The one-time capital costs include implementation of an AM/FM Geographic Information System ("AM/FM GIS").[19] In gas supply, NEGas will eliminate 7 positions savings of $648,773 with total one-time O&M costs of $147,000.

In his pre-filed testimony, John Quain, consultant for NEGas, discussed performance-based ratemaking ("PBR") and incentive mechanisms. Mr. Quain stated that PBR should include benchmarks to be achieved, a mechanism to measure performance, delineation of the frequency and duration of measurement intervals, incentives and penalties.[20] Mr. Quain noted that the Commission adopted a PBR plan

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[15] Id., Exhibit TEC-3, p. 1.
[16] Id., Exhibit TEC-3, p.1.
[17] Id., pp. 26-28.
[18] Id., Exhibit TEC-3, p. 1.
[19] Id., pp. 32-33.
[20] NEGas Ex. 6: (Quain's pre-filed testimony), pp. 5-6.

for the Narragansett Electric Company and stated that NEGas has proposed an ESM and will develop a Service Quality Plan ("SQP").[21]

In his prefiled testimony, John Dunn, consultant for NEGas, discussed NEGas' proposed capital structure, capital costs and rate of return. Because NEGas, a division of Southern Union, does not have its own capital structure or cost of debt, Mr. Dunn analyzed a group of comparable companies to create a capital structure and used the Discounted Cash Flow model ("DCF") to establish the cost of equity.[22] Based on his analysis of comparable companies, Mr. Dunn proposed that the capital ratio for NEGas be 49.3% equity, 6.7% short-term debt, 2.0% preferred equity and 42.0% long-term debt. Mr. Dunn also proposed the cost of long-term debt as 8.0%, the cost of short-term debt as 7.5%, the cost of preferred equity as 8.0%, and the cost of common equity as 12.5% for an overall rate of return as 10.18%.[23] Mr. Dunn did not utilize the capital structure rates of Southern Union, because Southern Union's capital structure is designed to cause it to have investment grade debt securities. Southern Union's capital structure ratio consisted of long-term debt of 46.78%, preferred equity of 6.38%, and common equity of 46.84%. According to Mr. Dunn, the use of the Southern Union capital structure would result in a modest increase in the rate of return because

[21] Id., pp. 10-12.
[22] NEGas Ex. 7: (Dunn's pre-filed testimony), p.3.
[23] Id., pp. 3-4.

Southern Union has no short-term debt.[24] In addition, Mr. Dunn recommended that if a lower common equity ratio is used then the cost of equity should be increased.[25]

In his pre-filed testimony, Mr. Christopher Gulick, consultant for NEGas, discussed the integration of gas supply management functions and resource portfolios for the pre-merger entities of NEGas. NEGas' objective is to minimize operating costs without compromising safety or reliability.[26] Integration of gas supply dispatch and control will result in labor related savings of approximately $0.65 million annually after a one-time cost of approximately $0.15 million.[27] Mr. Gulick noted the gas portfolio integration will not affect NEGas' ability to pursue the objective of price stability and affordability under current or future gas purchasing programs.[28]

Mr. Gulick outlined the benefits of the consolidation of NEGas' gas portfolio for its customers. First, NEGas will be able to use its existing transportation agreements to provide gas supplies where most needed and may be able to reduce the need to vaporize Liquefied Natural Gas ("LNG") in one area where adequate pipeline supply is available in another. Also, consolidation will give NEGas access to a broader array of gas resources and be less susceptible to disruptions in any one resource.

[24] Id., pp. 8-10.
[25] Id., p. 14.
[26] NEGas Ex. 9: (Mr. Gulick's pre-filed testimony), pp. 4-5.
[27] Id., p. 7.
[28] Id., p. 25.

Lastly, consolidation could increase the load factor and reduce the average cost of gas.[29]

In pre-filed testimony, Mr. David Heintz, consultant for NEGas, discussed NEGas' cost of service study ("COSS") and proposed rate design. According to Mr. Heintz, a primary goal of NEGas is to implement a "one-state, one-rate" tariff while tempering the impact to ratepayers.[30] NEGas proposed consolidating and eliminating the existing rate schedules by developing eight firm service offerings: two residential services (Heating & Non-Heating), six C&I service offerings (Small, Medium, Large Low Load Factor, Large High Load Factor, Extra Large Low Load Factor High Load Factor, Extra Large Low Load Factor), and two miscellaneous service offerings (Natural Gas Vehicles & Gas Lighting). Also, NEGas proposed two non-firm service offerings (Non-Firm Sales and Non-Firm Transportation).[31] Mr. Heintz explained that NEGas' proposed rate design will recover only costs related to investment in, and operation of the distribution system, while costs related to the purchase of gas will go through the GCRC. In addition, the DAC will collect costs related to system pressure, demand side management ("DSM"), low income assistance programs, environmental remediation,

[29] Id., pp. 26-27.
[30] NEGas Ex. 11: (Mr. Heintz's pre-filed testimony), p. 5.
[31] Id., pp. 6-7.

and incentive provisions for service quality, merger savings and non-firm service.[32]

Mr. Heintz discussed the COSS performed by NEGas to determine the cost responsibility of NEGas' various rate classes. Mr. Heintz noted that all gas costs are not included in the COSS because removing gas costs from base rates will enable customers who are eligible for transportation to more readily compare the cost of purchasing from a competitive marketer.[33] Mr. Heintz also stated that NEGas' LNG O&M expenses used for supply purposes are not included in the COSS, but LNG O&M related system balancing are included in the COSS. Accordingly, Mr. Heintz removed 79.61% of LNG O&M costs from the COSS and placed it in the GCRC.[34] Based on the COSS, Mr. Heintz concluded that residential classes are being subsidized by non-residential classes while C&I classes are all above the overall rate of return.[35]

Mr. Heintz discussed ProvGas' & Valley's current rate structure. For residential customers, the rates for Valley's heating class consists of a customer charge and a declining block commodity charge while Valley's non-heating class rate structure consists of a customer charge and a flat commodity charge. For residential customers, the rates for ProvGas' heating and non-heating classes consist of a customer charge and a

[32] Id., pp. 8-9.
[33] Id., pp. 10, 16.
[34] Id., pp. 16-17.

declining block commodity charge.[36] A majority of Valley's C&I customers are small users and have rates that consist of a customer charge and a declining block commodity charge. The remaining C&I customers of Valley belong to various rate classes that consist of a customer charge, a demand charge and a declining block commodity charge while ProvGas' larger C&I customers have rate structures consisting of a customer charge, demand charge and a flat commodity charge.[37]

Mr. Heintz reviewed NEGas' proposed rate design. As for volume and revenue adjustments, Mr. Heintz made adjustments based on major customers leaving NEGas' system, weather and expected growth from the test year. For the weather, Mr. Heintz used a 10-year average ending September 2000, which had 5,492 heating degree-days ("HDD").[38] The growth percentages were based on the historical experience of ProvGas and Valley, and increased the revenue by $5,775,851. Mr. Heintz mentioned that NEGas is proposing to move from a volumetric billing basis to a therm billing basis.[39] Mr. Heintz noted that adjustments were made to ProvGas' actual revenues including: moving purchased gas costs to GCRC, removing the ERI II settlement amount from gas costs, moving Integrated Resource Planning ("IRP") revenues to DAC, adjusting non-

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[35] Id., p. 18.
[36] Id., p. 20.
[37] Id., pp. 21-22.
[38] Id., p. 23.
[39] Id., pp. 23-25.

firm sales and transportation revenues, adjusting unbilled revenues to zero, and eliminating exogenous revenue.[40]

Mr. Heintz described NEGas' proposed residential rate design. The residential heating class will have a customer charge and a declining block usage rate similar to ProvGas' existing rate structure. The residential non-heating class will have a customer charge and a single usage rate similar to Valley's existing rate structure. In addition, NEGas proposed that residential heating rate schedules recover their current level of distribution revenues plus additional revenue responsibility of $750,000 formerly borne by Large and Extra Large C&I classes. Also, NEGas proposed increasing the customer charge to $8.00 from $7.00 for ProvGas non-heating residential customers and to $8.00 from $5.43 for Valley non-heating residential customers. Mr. Heintz characterized this as a move toward full recovery of customer-related costs because, according to the COSS, the customer-related costs for this class are $20.29 per customer per month.[41] For residential heating customers, NEGas proposed increasing the customer charge from $8.00 to $10.00 for ProvGas' customers and from $5.43 to $10.00 for Valley's customers. The COSS determined that customer-related costs for this class are $22 per customer per month.[42] The proposed block break for the residential

[40] Id., p. 26.
[41] Id., pp. 32-33.
[42] Id., p. 33.

heating class is 80 therms in the peak period and 25 therms in the off-peak, while the non-residential heating class has no block break.

In summary, Mr. Heintz stated that utilizing current gas costs, approximately 50% of ProvGas' residential non-heating customers will experience a minor rate increase and the remaining residential non-heating customers will experience a minor rate decrease. On the other hand, the average Valley residential non-heating customer will experience a rate increase of $48 a year. As for residential heating customers, utilizing current gas costs, ProvGas' customers will experience a minor rate decrease and the average Valley customer will experience a rate increase of 14%. If projected gas costs are utilized, however, the proposed increases are mitigated and proposed decreases become more substantial. For instance, the average Valley residential heating customer would only experience a 6% increase utilizing projected gas costs.[43]

In regards to the proposed C&I rate structure, the small C&I class will have a customer charge and a declining block commodity charge while the medium, large and extra large C&I classes will have a rate structure consisting of a customer charge, a demand charge and a flat commodity charge. Mr. Heintz noted that small and medium C&I rate schedules recover their current distribution revenues while a portion of the existing revenues for large and extra large C&I classes was assigned

[43] Id., pp. 33-35.

to the residential heating class. In summary, Mr. Heintz stated that utilizing current gas costs, ProvGas' small, medium, lowload, large and extra large C&I customers will generally experience rate decreases and only Medium High Load customers will see minor rate increases. In general, Valley's C&I customers will experience rate increases, but the higher a customer's usage the lower the rate increase will be.[44]

In his pre-filed testimony, Mr. Peter Czekanski, Director of Pricing for NEGas, discussed NEGas' proposed consolidated tariff, the GCRC and DAC. NEGas proposed a common set of terms and conditions for ProvGas and Valley customers. The two primary changes that will affect only Valley customers are a change in the grace period from 30 to 25 days after the date of the bill for accrual of a late payment charge on non-residential bills and the implementation of an interest rate on customer deposits equal to the rate paid on ten-year U.S. Treasury bonds for the preceding year. Another new provision in the terms and conditions is a returned check charge of $15.[45]

Mr. Czekanski also discussed the proposed weather normalization provision in the tariff. The new weather normalization provision will result in a weather adjustment on each customer's bill each month from November through April to the extent that the weather varies from what is normal.[46] In addition, Mr. Czekanski noted changes that will affect

[44] Id., pp. 36-39.
[45] NEGas Ex. 12: (Mr. Czekanski's pre-filed testimony), pp. 6-7.
[46] Id., pp. 8-9.

ProvGas' customers such as separately identifying the Rhode Island Gross Earnings Tax, removal of unregulated service charges from the tariff and the inclusion in the tariff of an Account Restoration Charge of $25.[47]

In regards to the GCRC, Mr. Czekanski explained that the GCRC is designed to recover costs associated with gas supply. The two key changes relating to the GCRC is that each rate class receives a different gas cost factor and all gas-related costs are moved from base rates to the GCRC.[48]

As for the DAC, Mr. Czekanski explained that it is designed to annually recover system balancing, low-income assistance programs, DSM and environmental response costs ("ERC"). In addition, the DAC will include incentive provisions related to margins from non-firm sales and transportation, merger related savings and the SQP.[49] System balancing is the assignment of that portion of LNG costs that are incurred to maintain system pressures, which is 20.39% for NEGas. Low Income Assistance Programs included in the filing are $1,585,000 for the Low Income Heating Energy Assistance Program ("LIHEAP") and $200,000 for the Low Income Weatherization Program. Also, the DAC includes a $300,000 DSM program.[50]

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[47] Id., p. 11.
[48] Id., pp. 12-13.
[49] Id., p. 14.
[50] Id., pp. 14-15.

The DAC includes the ERC Factor, which is designed to allow NEGas to recover its reasonable and prudently incurred costs for evaluation, remediation and clean up of the sites associated with NEGas' ownership and operation of manufactured gas plants, storage facilities and off-site waste disposal locations. The ERC factor is a charge that reflects a 10-year amortization of ERC, and ProvGas has $12.4 million in unrecovered ERC.[51] Mr. Czekanski explained that Net Insurance Revenues are environmental response costs recovered from insurers and third parties less the cost of obtaining such proceeds through litigation. The ERC factor includes one-half of the Net Insurance Revenues and amortizes them over a 10-year period. According to Mr. Czekanski, the formula provides strong incentives for NEGas to obtain insurance and third party proceeds while sharing the risk and rewards of these efforts between shareholders and customers. In addition, Mr. Czekanski noted that NEGas will not seek interest on its substantial balance of unamortized ERC.[52] In the area of non-firm sales, Mr. Czekanski explained that the margin will be established at $1.2 million and that customers will receive 25% of revenues above this threshold.[53]

Mr. Czekanski discussed the proposed switch from volumetric billing to therm billing. He explained that therm billing recognizes the heat content of each unit of gas. He suggested that therm billing will

[51] Id., pp. 16-17.
[52] Id., pp. 17-18.
[53] Id., p. 19.

allow customers eligible to purchase gas from a third-party gas marketer to better compare prices. Mr. Czekanski emphasized that the proposed conversion to therm billing will have no impact on charges to NEGas customers.[54]

For the GCRC, Mr. Czekanski stated that the proposed factors in this filing are based on projected gas costs from October 2001 to September 2002. He explained that NEGas will update the GCRC factor on or about May 1, 2002 for effect July 1, 2002.[55] The proposed DAC factor in this filing is $0.0117 per therm. This cost reflects: 20% of the LNG costs related to maintaining system pressures, $300,000 for DSM, $1,585,000 for LIHEAP, $200,000 for the Low Income Weatherization Program, and $678,282 for ERC.[56]

II. <u>DIVISION'S FILING</u>

On March 15, 2002, the Division submitted the pre-filed testimony of its consultants, David Effron, Matthew Kahal, Richard LeLash, and Bruce Oliver. In his pre-filed testimony, Mr. Effron discussed the stand-alone revenue requirements of the pre-merger companies, the effect of the merger on revenue requirements and the quantification of merger savings to be shared with ratepayers. Mr. Effron determined that ProvGas has a revenue excess of $6,570,000 and Valley has a revenue

[54] Id., pp. 20-21.
[55] Id., pp. 29, 33
[56] Id., pp. 33-35.

deficiency of $170,000. After the incorporation of merger savings, the revenue excess for NEGas is $8,073,000.[57]

Mr. Effron made various adjustments to ProvGas' operation and maintenance expenses. Mr. Effron reduced ProvGas' uncollectible accounts expense from $7,008,000 to $3,799,000. ProvGas had determined this expense by reviewing the twelve-month period ending September 30, 2001, which had abnormally high Purchased Gas Adjustment ("PGA") revenues. Instead Mr. Effron utilized a five-year average of net account write-offs that amounts to 2.02%.[58] Mr. Effron reduced ProvGas' health insurance expense from $5,438,000 to $4,978,000 by eliminating ProvGas' expected increase in head count.[59] Also, Mr. Effron reduced ProvGas' labor expenses from $29,786,000 to $27,604,000 by eliminating the hiring of new employees and reducing the projected increase in wages. Furthermore, Mr. Effron reduced by $165,000 the erosion adjustment for ProvGas by using an inflation rate of 1.80% annually instead of a range of 2.76% to 2.30% annually.[60]

Mr. Effron made a number of additional adjustments to ProvGas' revenue requirements. He reduced ProvGas' depreciation and amortization by $86,000. In addition, Mr. Effron proposed adjustments to: the R.I. Gross Receipts Tax to reflect his proposed revenue reduction; to the FICA tax to reflect the reduction in the operating labor expense; a

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[57] Div. Ex. 1: (Effron's pre-filed testimony), pp. 4-5.
[58] Id., pp. 6-8.
[59] Id., pp. 9-10.

reduction in property taxes in the amount of $940,000 due to a change in R.I.G.L. § 44-5-11.8 relating to the city of Providence. Also, he calculated an adjustment to the income tax expense due to the changes made to the rate of return and the rate base and adopted Mr. Kahal's proposed rate of return of 8.98%.[61]

Mr. Effron also made a number of adjustments to ProvGas' rate base. He reduced the plant in service expense by $4,410,000 by eliminating forecasted additions to intangible plant and storage plant. He proposed eliminating the prepayments related to insurance, which reduces the rate base by $509,000, and to taxes, which reduces the rate base by $1,880,000.[62] Regarding deferred debts, Mr. Effron reduced the amount from $5,603,000 to $3,129,999 primarily by eliminating the unamortized legacy CIS costs from the rate base because the legacy CIS is not used and useful. As for accumulated deferred income taxes, Mr. Effron determined that they are growing and therefore, he increased the balance of these taxes by $1,134,000.[63]

Mr. Effron made two adjustments to ProvGas' operating revenues. First, he included the effect of sales growth resulting in a net revenue increase of $1,582,000 and a corresponding decrease in ProvGas' standalone revenue deficiency.[64] Second, Mr. Effron assumed that usage

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[60] Id., pp. 10-13.
[61] Id., pp. 14-17.
[62] Id., pp. 19-21.
[63] Id., pp. 21-24.
[64] Id., pp. 25-26.

per customer will remain constant, resulting in a net revenue increase of $862,000 and a corresponding decrease in ProvGas' revenue deficiency.[65]

For Valley, Mr. Effron determined that there was a revenue deficiency of $170,000.[66] In the area of Valley's operation and maintenance expense, Mr. Effron reduced the health insurance expense by $365,000. He reduced Valley's operating labor expense by $107,000 utilizing the same methodology he utilized for ProvGas. In addition, Mr. Effron reduced the erosion adjustment expense by $215,000.[67] Furthermore, Mr. Effron increased Valley's depreciation expense by $39,000. In accordance with his other adjustments, Mr. Effron adjusted Valley's R.I. Gross Receipts tax, FICA tax and income tax. As for the return on rate base, Mr. Effron utilized Mr. Kahal's recommendation of 8.98%.[68]

In the area of Valley's rate base, Mr. Effron reduced the plant in service expense by $4,041,000 due to the elimination of the ERT investment. Also, Mr. Effron eliminated prepaid insurance thereby reducing $1,224,000 from the rate base and eliminated prepaid taxes thereby reducing $287,000 from the rate base. However, Mr. Effron increased Valley's accumulated deferred income taxes by $327,000.[69]

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[65] Id., pp. 27-28.
[66] Id., p. 28.
[67] Id., pp. 30-32.
[68] Id., pp. 32-33.
[69] Id., pp. 34-36.

As for operating revenues, Mr. Effron included sales growth resulting in a net revenue increase to Valley of $1,579,000 and accordingly, a decrease in Valley's standalone revenue deficiency by the same amount. Also, Mr. Effron determined that the combined margin or interruptible sales for NEGas is $1,600,000.[70]

By combining the stand-alone revenue requirement of the pre-merger companies, Mr. Effron determined that there was a combined revenue excess of $8,073,000. Mr. Effron arrived at this figure by determining that the combined revenue excess is $6,400,000 plus four adjustments. The first adjustment is for security enhancements totaling $315,000. The second adjustment is the amortization of rate case costs. The third adjustment is a credit to revenues totaling $140,000 from an account restoration charge and proposed returned check charge. Fourth, Mr. Effron incorporated one-half of net merger savings amounting to $2,049,000 into the NEGas revenue requirement.[71]

In the area of merger-related savings, Mr. Effron determined that NEGas' average annual net merger-related savings for the period FY 2003-2005 will be $4,099,000. Mr. Effron determined that NEGas would have total gross annual merger-related savings of $11,458,000 through 2005. These savings consist of $2,960,000 in savings already achieved, of which $2,739,000 is due to labor cost reductions. Also, these savings consist of $5,824,000 in average annual savings to be achieved from

[70] Id., pp. 37-38.

2003 through 2005, of which $5,247,000 will be due to labor cost reductions. In addition, Mr. Effron included $1,928,000 in merger-related savings from insurance expense being shifted to Southern Union. Furthermore, Mr. Effron included $746,000 in merger-related savings from public company expenses being shifted to Southern Union.[72]

In the area of merger-related costs, Mr. Effron determined that the amount will total $7,359,000 through 2005. These costs include: $710,000 in average annual severance costs, $235,000 in average annual operation and maintenance costs, $465,000 in integration/rate design costs amortized over three years, corporate allocation costs of $4,426,000, and average annual capital costs of $1,796,000. The corporate allocation cost from Southern Union includes $1,960,000 of functional labor expense, and $2,466,000 of non-labor expenses, of which $1,449,000 is insurance expense. Also, Mr. Effron reduced merger-related costs by $273,000 because they relate to management salaries and benefits in Massachusetts.[73]

In conclusion, Mr. Effron subtracted the total merger-related costs from merger-related savings for the period FY 2003-2005 and determined there will be average annual net merger-related savings of $4,099,000. Mr. Effron recommended that a reasonable sharing of the risks and rewards of the merger would be a 50/50 sharing between investors and

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[71] Id., pp. 39-40.
[72] Id., pp. 40-44.
[73] Id., pp. 44-48.

ratepayers. This will reduce the NEGas revenue requirement by $2,049,000 and thereby produce a total revenue excess of $8,073,000.[74]

In his pre-filed testimony, Mr. Kahal discussed NEGas' rate of return. Mr. Kahal recommended a return on rate base of 8.98 percent and a ROE of 11.00 percent. Mr. Kahal recommended a capital structure of 43.6 percent common equity, 45.8 percent long-term debt, 8.8 percent short-term debt and 1.9 percent preferred tock. In addition, he recommended a short-term debt rate of 4.86 percent and a long-term debt rate of 7.81 percent. Mr. Kahal also determined that the inflation factor for 2001 is 2.2 percent, for 2002 is 1.4 percent, and for 2003 is 1.8 percent.[75] Mr. Kahal noted that in the recent past, the Commission had awarded the two pre-merger companies a ROE of 10.9 percent while ProvGas had common equity ratio of 43.1 percent and Valley had a ratio of 41.0 percent. Although NEGas does not have a separately identifiable capital structure, he noted that prior to the merger, the common equity ratio for ProvGas was 42.3 percent and 42.6 percent for Valley.[76]

Mr. Kahal utilized the DCF method for determining NEGas' capital structure and return on common equity. Mr. Kahal stated that the traditional approach to the capital structure is to utilize the actual capitalization data of the regulated utility as long as the capital structure is reasonable and economical. However, NEGas does not have an

[74] Id., pp. 48-50.
[75] Div. Ex. 3: (Mr. Kahal's pre-filed testimony), pp. 3-4, 16.
[76] Id., pp. 4-6.

identifiable capital structure because it is financially integrated with Southern Union.[77] Thus, Mr. Kahal decided the two best approaches were to use the actual capital structure of Southern Union or to use a hypothetical capital structure based upon actual capitalization data for the gas local distribution company ("LDC") industry. Although the use of Southern Union's capital structure is conceptually valid and reasonable, Mr. Kahal determined that Southern Union's capital structure is unduly weak with a common equity ratio below 30 percent. Accordingly, Mr. Kahal used a group of 14 gas LDC companies reasonably comparable to NEGas for developing a hypothetical capital structure and ROE.[78]

After a review of the proxy group of 14 gas LDC companies as of September 30, 2001, Mr. Kahal determined the average ratio is 43.4 percent long-term debt, 13.6 percent short-term debt, 1.8 percent preferred stock and 41.3 percent common stock. Mr. Kahal did not recommend using 13.6 percent for short-term debt because it was merely a snap shot as of September 30, 2001. Instead, Mr. Kahal utilized Southern Union's 2001 average monthly balance to determine the short-term debt would be 8.79 percent. Accordingly, Mr. Kahal recommended the following hypothetical capital structure be used for NEGas: 45.75

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[77] ProvGas and Valley ceased to exist as corporate entities upon the completion of the merger with Southern Union.
[78] Id., pp. 9-11.

percent long-term debt, 8.79 percent short-term debt, 1.87 percent preferred stock, and 43.58 percent common equity.[79]

As to the cost rates, Mr. Kahal recommended 4.86 percent for short term debt cost because it was the average short-term debt cost incurred by Southern Union in 2001. Mr. Kahal noted that short-term debt rates fell below 3 percent by the end of 2001, but utilized 4.86 percent as more representative of future conditions. For long-term debt, Mr. Kahal used 7.81 percent, which is Mr. Dunn's estimate of the actual ProvGas and Valley embedded cost rate, and noted that this rate is similar to the embedded cost of debt for Southern Union. Also, since neither ProvGas or Valley has any outstanding preferred stock, Mr. Kahal used the 1.87 ratio of his proxy group and Southern Union's cost rate of 9.93 percent.[80]

Mr. Kahal noted various differences between his analysis and Mr. Dunn's analysis. For instance, Mr. Kahal included Southwest Gas and NICOR in his proxy group while excluding UGI from the proxy group. Also, Mr. Kahal noted that Mr. Dunn improperly excluded current maturities from long-term debt. Also, Mr. Kahal stated that the data Mr. Dunn utilized is stale because it goes back to 2000. Furthermore, Mr. Kahal disagreed with Mr. Dunn's use of 7.5 percent for the cost of short-term debt. Mr. Kahal noted that the bank prime rate was 4.75 percent in

[79] Id., pp. 11-12.
[80] Id., pp. 12-13.

January 2002 and large utilities are able to borrow short-term at rates below the bank prime rate.[81]

As for the cost of common equity, Mr. Kahal utilized the DCF model and applied it to his proxy group because NEGas is not publicly traded and Southern Union pays no dividend. Utilizing the DCF model, Mr. Kahal determined that NEGas' adjusted dividend yield is 4.75 percent and the growth range is 6.0 to 6.5 percent, which combined for a total return of 10.75 to 11.25 percent. The midpoint is 11.0 percent, which is his ROE recommendation for NEGas. Also, Mr. Kahal disagreed with Mr. Dunn's determination that NEGas' common equity would be riskier due to its small size because NEGas is part of a large company, Southern Union.[82]

In his pre-filed testimony, Mr. LeLash discussed ESMs, service measures and benchmarks, weather normalization and the DAC. Mr. LeLash noted that NEGas proposed two ESMs: one for non-firm margins and a second for earnings in excess of the ROE of 12.5 percent. In general, Mr. LeLash stated that an ESM should provide rewards to shareholders for superior performance, balance rewards and penalties, and provide an adequate definition and measurement of performance and return levels. [83]

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[81] Id., pp. 14-16.
[82] Id., pp. 17, 24-26.
[83] Div's Ex. 4: (LeLash's pre-filed testimony), pp. 17-18.

In the area of non-firm margins, Mr. LeLash noted that ProvGas and Valley have averaged $2.1 million in non-firm margin sales annually over the past five years. Consequently, Mr. LeLash recommended that the $1.2 million threshold proposed by NEGas should be increased to at least $1.6 million. In addition, he recommended that the ratepayers receive 75 percent of non-firm margins above $1.6 million instead of 50 percent, while NEGas would receive funds through the DAC if non-firm margin sales fell below $1.6 million.[84]

In regards to ROE sharings, Mr. LeLash utilized 11.0 percent as NEGas' ROE and recommended that the ratepayers share be 50 percent of earnings between 11.0 percent and 12.0 percent, and that the ratepayers share be 75 percent for earnings in excess of 12.0 percent. He rejected NEGas' proposal for shareholders to retain as much as 75 percent of earnings above the authorized ROE, in particular because weather normalization reduces risk to shareholders.[85] Also, Mr. LeLash recommended that an ESM remain in effect for a period no longer than eight years, that under ESM the ROE will not be adjusted for exogenous events, and that cost savings be excluded from the measurement of actual achieved ROEs.[86]

In the area of service measures and benchmarks, Mr. LeLash expressed concern that in an attempt to maximize earnings through staff

[84] Id., pp. 20-22.
[85] Id., 23-25,
[86] Id., pp. 25-28.

reductions, NEGas' level of service may adversely be affected. He noted that NEGas is working with the Division to develop a comprehensive service quality measurement and monitoring plan. Mr. LeLash emphasized that no ESM should be approved until a SQP is fully developed and implemented. Although it may take time to accumulate baseline statistics on NEGas' performance, Mr. LeLash recommended developing interim SQP standards based on data collected from other utilities. In addition, Mr. LeLash discussed potential SQP measures such as overall customer satisfaction, service reliability, phone inquiry response time and abandonment, number of sustained customer complaints, written inquiry response time, meters read on cycle, field service response time, level of held service applications and percentage of service requests cleared. Also, Mr. LeLash noted that any penalty provision in the SQP should be specified.[87]

As for weather normalization, Mr. LeLash noted that NEGas is proposing a Type 1 weather normalization provision, which provides customers with a monthly weather adjustment between November and April with no deadband. This proposal differs from the Type 2 weather normalization provision utilized by ProvGas with a deadband.[88] Mr. LeLash supported the use of weather normalization in general because it is a revenue neutral mechanism, which benefits the utility and

[87] Id., pp. 29-31.

ratepayers. Specifically, Mr. LeLash supported a Type 2 mechanism to avoid customer confusion. He noted that weather normalization should be for abnormal variations in weather and therefore should utilize a 3 percent deadband with a ten year HDD average as the benchmark.[89]

In regards to the DAC, Mr. LeLash noted that it is a mechanism intended for recovering or crediting DSM, low income assistance, weatherization program costs, non-firm margins, ESM credits, ERC and SQP on an annual basis. Mr. LeLash explained that absent a DAC, the ESM and SQP components would require a relatively complex adjustment process. On the other hand, Mr. LeLash stated that DAC allows what are often base rate recovered components to be subject to reconciliation and effective pass through rate treatment. At the outset, Mr. LeLash stated that more than 30 days was required to ensure adequate time for review.[90]

Specifically addressing ERC, Mr. LeLash explained that the ERC would be part of the DAC and that environmental costs would be amortized over a ten-year period. He noted that because these costs are deferred with no carrying costs on the unamortized balance, there is an implicit sharing of the environmental costs between ratepayers and shareholders. He also noted that NEGas proposed to credit the ERC with

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[88] Under a Type 2 weather normalization provision, the impacts from an allowable weather variance would be adjusted in the following year rather than on a current, monthly basis.
[89] Id., pp. 34, 36-37.
[90] Id., pp. 38-40.

50 percent of net insurance recoveries. However, Mr. LeLash recommended that all insurance proceeds and any net proceeds on sales of remediated properties should be credited to the ERC. In addition, Mr. LeLash made various modifications regarding ERC which differed slightly from the methodology presently utilized in Massachusetts.[91]

In his pre-filed testimony, Mr. Oliver discussed tariff language and rate design related issues. At the outset, he noted that Valley's rates are generally lower than ProvGas' rates and therefore, consolidation will be less advantageous to Valley's customers. He contrasted this situation to the NEES/EUA merger in which the larger utility Narragansett Electric was the lower cost utility. Also, Mr. Oliver noted that NEGas was requesting a revenue increase, which would result in significant double-digit increases for Valley's customers.[92]

In the area of rate consolidation, Mr. Oliver noted that NEGas used ProvGas' rate schedules as a starting point. He stated that the Division is supportive of rate consolidation but is concerned regarding the magnitude of the rate increases for Valley residential customers. Thus, Mr. Oliver argued that any rate consolidation must be gradual regarding rate impacts. Mr. Oliver recognized that delaying or denying NEGas' request to consolidate rates could result in additional annual costs of $766,000 to $966,000.[93] To minimize increases for Valley customers,

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[91] Id., pp. 40-44.
[92] Div. Ex. 5: (Oliver's pre-filed testimony), pp. 5-6.
[93] Id., pp. 16-17, 22,

Mr. Oliver recommended that increases be held to modest percentages of 5 to 7 percent or where the impact on the customer's monthly bill is less than $4.00 per month. In addition, he stated that NEGas' overall revenue requirement should be set low and the first $1.6 million dollars of savings for customers should go to Valley's customers.[94]

In the area of class revenue requirements, Mr. Oliver noted that NEGas reallocated $750,000 of the existing base-rate revenue requirements for Large & Extra Large C&I customers to residential heating customers and that the entirety of the rate increase will come from residential, small C&I and medium C&I customers. He disagreed with NEGas placing a greater than system average increase on the Medium C&I class and making no adjustment to the Large Low Load Factor C&I class. In contrast, Mr. Oliver recommended that the Medium C&I class be exempted from a rate increase but he supported a small revenue increase for Small C&I and for the residential classes.[95]

In the area of class costs of service, Mr. Oliver expressed concern regarding the COSS utilized by NEGas. First, Mr. Oliver noted the COSS is devoid of any systematic assessment of its costs of providing either firm transportation service or non-firm services. Second, Mr. Oliver was troubled by the presumption that costs incurred for transportation

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[94] Id., pp. 24-26.
[95] Id., pp. 26, 30, 32-34.

service benefit all customers and should therefore be allocated among all classes.[96]

In regards to rate design, Mr. Oliver discussed NEGas' proposal for: conversion to therm billing, increases in customers charges and head block commodity charges, adjustments to the size of the head block, elimination of all recovery of gas supply related costs from base rates, implementation of Type 1 weather normalization, and introduction of DAC.[97] Mr. Oliver did not oppose therm billing but believed that a Therm Billing Adjustment Factor should be annual or seasonal.[98] Mr. Oliver opposed implementation of Type 1 weather normalization because of customer confusion, the needs for audits and the difficulty of making subsequent adjustments to bills. For the DAC, Mr. Oliver recommended delaying implementation until October 1 annually.[99] In addition, Mr. Oliver opposed eliminating all gas cost recovery from distribution charges because it complicates rates and the GCRC, and furthermore does not benefit residential customers.[100] Also, Mr. Oliver asserted that any customer who uses gas during a period when LNG peaking resources are utilized should share in the LNG's costs instead of NEGas' proposal of only having heating customers pay for LNG peaking costs.[101]

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[96] Id., p. 39.
[97] Id., p. 42.
[98] Id., pp. 43, 46.
[99] Id., pp. 47-48, 50.
[100] Id., pp. 51-53.
[101] Id., pp. 54-55.

Regarding residential rate design, Mr. Oliver advocated for maintaining the current head block size for residential heating customers so as to moderate the range of bill impacts. Also, Mr. Oliver concurred with the adoption of new higher monthly customer charges but indicated that it may be appropriate to defer some of the proposed increases to mitigate the impact on Valley's customers. Furthermore, Mr. Oliver stated that the Commission should consider eliminating the subsidization of non-heating residential customers because the pace of conversions to residential heating service has diminished.[102]

For Small C&I rate design, Mr. Oliver supported a monthly $15 customer charge and the elimination of the distinction between high load and low load Small C&I.[103] For Medium, Large and Extra Large C&I rate design, Mr. Oliver stated that the methodology used to design the rates appeared reasonable but he had concerns over the accuracy of measures of customer costs and the equalization of customers costs for sales service and transportation services.[104] For Non-Firm Services, Mr. Oliver had several problems including the need for an updated cost of service analysis to support the level of NEGas' proposed Customer Charges and Minimum Charges, and a method for eliminating the use of value of service pricing for non-firm gas services.[105] For Gas Lamps and Natural Gas Vehicles, Mr. Oliver recommended increasing the rates for these two

[102] Id., pp. 57-62.
[103] Id., pp. 64-67.
[104] Id., pp. 67-68.

charges to more closely reflect their cost-based levels.[106] For the remaining charges, Mr. Oliver recommended establishing a penalty for the unauthorized use of gas that is set at three times the referenced Gas Daily index rates for New England city gates and that these penalty revenues should flow back to customers through the GCRC. He concurred with NEGas' $25 account restoration charge, and recommended implementing a $20 charge for a returned check.[107]

III. NEGAS' REBUTTAL

On March 29, 2002, NEGas filed rebuttal testimony by Sharon Partridge, John Quain, John Dunn, David Heintz and Peter Czekanski. In her pre-filed testimony, Ms. Partridge discussed Mr. Effron's cost of service and rate base adjustments for ProvGas and Valley as well as Mr. Effron's merger-related adjustments to NEGas' combined revenue requirement.

For ProvGas' revenue deficiency, Ms. Partridge disagreed with Mr. Effron's adjustments to uncollectible-accounts expense because she had determined that the Commission's policy change on service terminations will increase uncollectibles. Also, Ms. Partridge opposed Mr. Effron's adjustments to the health insurance expense because ProvGas' benefits consultant anticipated an increase of 25.65 percent by 2003. Regarding Mr. Effron's adjustments to operating labor, Ms. Partridge stated that

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[105] Id., pp. 70-72.
[106] Id., pp. 75-76.
[107] Id., pp. 77-81.

savings from the elimination of employment positions should be considered merger savings to be shared with shareholders. Ms. Partridge disagreed with Mr. Effron's adjustment to taxes because the recent change in state law affects personal property tax rates. In addition, Ms. Partridge did not concur with Mr. Effron's adjustments to plant-in-service because she categorized these savings as merger-related to be shared with shareholders. Also, she opposed Mr. Effron's adjustment to prepayments because the merger is the reason ProvGas will no longer be making insurance payments.[108]

In the area of Valley's stand-alone revenue deficiency, Ms. Partridge disagreed with Mr. Effron's health insurance adjustment because Valley's benefit consultant estimated a 30.55 percent increase by 2003. Also, she noted that Valley's labor increase will be 4 percent rather than Mr. Effron's recommendation of 3 percent. In addition, Ms. Partridge opposed Mr. Effron's adjustment to Valley's plant-in-service because AMR was planned prior to the merger. Furthermore, Ms. Partridge disagreed with Mr. Effron's adjustment regarding Valley's prepayments because Valley would have made insurance prepayments if not for the merger.[109]

Regarding, NEGas' revenue deficiency, Ms. Partridge disputed Mr. Effron's use of an annual average amount for merger savings because the savings will occur in stages. Also, Ms. Partridge did not agree that the

[108] NEGas Ex. 3: (Ms. Partridge's rebuttal testimony), pp. 3-10.

consolidation plan and associated rate filing should be considered a merger-related cost. In addition, Ms. Partridge disagreed with a 50/50 sharing of net merger sharings or of earnings above the authorized ROE because shareholders are at a greater risk if savings are not achieved.[110]

In his rebuttal testimony, Mr. Quain discussed Mr. LeLash's views on ESM. Mr. Quain disagreed with Mr. LeLash's recommendation that earnings above 11 percent be shared equally between ratepayers and shareholders. Mr. Quain argued that Mr. LeLash's recommendation would be a disincentive for NEGas to be efficient and increase its earnings. Furthermore, Mr. Quain stated that giving ratepayers 75 percent of earnings above 12 percent is an even greater discentive to NEGas to be efficient. In addition, Mr. Quain opposed Mr. LeLash's view that no ESM should be implemented until a SQP is in place. Instead, Mr. Quain stated that NEGas should be required to establish a SQP within a date certain and in the meantime, NEGas would file quarterly service quality reports. Also, Mr. Quain disputed Mr. LeLash's assertion that the ESM should be in place no longer than eight years. In Mr. Quain's view, the period should be at least 10 years to be an incentive to NEGas.[111]

In his rebuttal testimony, Mr. Dunn responded to the recommendations of Mr. Kahal regarding capital structure and cost of

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[109] Id., pp. 10-13.
[110] Id., pp. 13-17.
[111] NEGas Ex. 6: (Quain's rebuttal testimony), pp. 2-8.

capital. Mr. Dunn argued that Mr. Kahal's capital structure has too much debt because Mr. Kahal relied on data that contained abnormally high amounts of short-term debt. Accordingly, Mr. Dunn stated that NEGas' rate of equity is inappropriately low in Mr. Kahal's recommendation.[112]

Regarding cost of capital, Mr. Dunn suggested that Mr. Kahal did not utilize a forward-looking approach. For instance, Mr. Dunn noted that the Division's recommended short-term debt rate was too low because it reflected recent reductions in interest rates instead of reflecting likely interest rates in the future.[113] In the area of long-term debt, Mr. Dunn believed Mr. Kahal's approach was reasonable but that his own approach was more consistent because it was derived from a comparable group of companies.[114] As for the cost of common equity, Mr. Dunn criticized Mr. Kahal's analysis on the following bases: the change in utilities' policy so as to lead to higher growth in earnings, the lack of a pre-offering pressure adjustment in the divided yield calculation, and the failure to include a risk adjustment.[115]

In his pre-filed testimony, Mr. Heintz responded to issues raised by the Division relating to rate design. Mr. Heintz disagreed with Mr. Effron's revenue growth adjustments for ProvGas. Mr. Heintz countered that although there is growth in customers there is no growth in usage

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[112] NEGas Ex. 8: (Dunn's rebuttal testimony), pp. 3-9.
[113] Id., pp. 10-17.
[114] Id., pp. 18-20.

per customer and that this is a long-term trend.[116] Mr. Heintz did not concur with Mr. Oliver's proposed distribution of the revenue requirement. Assuming NEGas' revenue increase is approved, Mr. Heintz noted that Mr. Oliver's proposal would exacerbate bill impacts on nearly all rate classes. Also, Mr. Heintz responded to Mr. Oliver's criticism of NEGas' COSS. In addition, Mr. Heintz opposed Mr. Oliver's proposal to allocate the first $1.6 million in merger savings to Valley customers because it would be unworkable and a costly administrative burden. Furthermore, Mr. Heintz disagreed with Mr. Oliver's assertion that removing all gas costs from base rates or having separate gas cost factors for each rate class would complicate the proceeding.[117]

In his pre-filed testimony, Mr. Czekanski discussed therm billing, weather normalization, unauthorized use charges and non-firm margin sharing. Mr. Czekanski disagreed with Mr. Oliver's suggestion that there only be a seasonal or annual therm billing adjustment factor. In addition, Mr. Czekanski continued to support the implementation of a Type 1 weather normalization mechanism. Mr. Czekanski noted that if a Type 2 weather normalization mechanism was adopted, there should not be a 3 percent deadband.[118] Also, Mr. Czekanski maintained his position that the penalty for unauthorized use of gas should be five times the index price so as to stay consistent with Massachusetts and avoid

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[115] Id., pp. 20-21.
[116] NEGas Ex. 11: (Heintz's rebuttal testimony), pp. 1-4.
[117] Id., pp. 5-14.

arbitrage. Regarding non-firm margins, Mr. Czekanski disputed Mr. LeLash's recommendations because he noted non-firm margins are declining and shareholders bear a greater risk if the threshold level is not met. Furthermore, Mr. Czekanski reasserted his position that a sharing mechanism for net insurance and third party recoveries of environmental costs provides an appropriate incentive for NEGas.[119]

IV. DIVISION'S SURREBUTTAL

On April 19, 2002, the Division submitted pre-filed surrebuttal testimony of David Effron, Matthew Kahal, Richard LeLash and Bruce Oliver. In his surrebuttal testimony, Mr. Effron discussed NEGas' revenue requirement and responded to the rebuttal testimony of Ms. Partridge and Mr. Heintz. For ProvGas' revenue requirement, Mr. Effron reaffirmed his position on uncollectible account expense. He noted that Ms. Partridge does not know what specific changes there will be to the Commission's rules concerning service termination and restated that 2000 should be included in the five-year average. Addressing health insurance expense, he dismissed Ms. Partridge's statement that health insurance will increase by 25.65 percent because prior estimates have proven inaccurate. For labor expense, Mr. Effron stated merger savings should be calculated at the time the merger occurred and not based on a scenario where the merger had never occurred, especially since the number of ProvGas employees had been declining since 1998.

[118] NEGas Ex. 13: (Mr. Czekanski's rebuttal testimony), pp. 3-8.

Furthermore, Mr. Effron continued to use the 3 percent wage increase assumption because he stated he would not premise rate case expenses on press releases regarding labor negotiations.[120]

Regarding property taxes, Mr. Effron reaffirmed his reduction by noting the ProvGas had recently been paying less in taxes. For plant-in-service, Mr. Effron reiterated his use of the average balance of plant-in-service instead of the balance at the end of the year. As for prepaid insurance, Mr. Effron addressed Mr. Partridge's concern by treating the reduction as merger-related savings to be shared between investors and ratepayers. In addition, Mr. Effron responded to Mr. Heintz's criticisms of his sales growth projection. However, Mr. Effron accepted Mr. Heintz's adjustment relating to the loss of Pawtucket Power as a customer, thereby reducing rate year revenues by $453,000.[121]

With regard to Valley's revenue requirement, Mr. Effron disagreed with Ms. Partridge's view regarding health insurance expense using the same rationale he outlined for ProvGas. Mr. Effron continued to use a 3 percent increase for labor expense because Ms. Partridge provided no additional documentation to support her position. Regarding plant-in-service, Mr. Effron continued to argue for the use of the average balance of plant-in-service. Also, Mr. Effron stated that ERT units needed to be treated consistently and thus, the cost of the benefits of ERT units

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[119] Id., pp. 9-11.
[120] Div. Ex. 2: (Effron's surrebuttal testimony), pp. 2-6.
[121] Id., pp. 6-12.

should be treated as merger related. As for the prepaid insurance, Mr. Effron gave Valley the same treatment as ProvGas.[122]

In the area of NEGas' merger costs and savings, Mr. Effron criticized Ms. Partridge's recommendation to calculate merger savings utilizing a present-value method. Mr. Effron continued to categorize integration/rate design costs as being related to the merger. Furthermore, Mr. Effron reaffirmed his recommendation of 50/50 sharing of merger savings.[123]

In conclusion, Mr. Effron calculated a revised NEGas' revenue excess as $7,510,000. Also, Mr. Effron determined that NEGas' firm distribution rate revenue requirement is $118,986,000.[124]

In his surrebuttal testimony, Mr. Kahal responded to Mr. Dunn's criticism of his recommendations regarding capital structure and rate of return. Regarding capital structure and debt costs, Mr. Kahal noted that he had reduced the short-term debt percentage of the proxy group from 13.6 percent to 8.8 percent, which is Southern Union's 12 month average. Also, Mr. Kahal stated that Southern Union's 2001 short-term debt was not abnormal. In addition, Mr. Kahal stated it was standard practice to consider current maturities as long-term debt for rate of return purposes. As for the cost of short-term debt, Mr. Kahal noted that Mr. Dunn provided no evidence that Southern Union's historic borrowing

[122] Id., pp. 12-14.
[123] Id., pp. 14-17.
[124] Id., pp. 17-20, Ex. DJE-4.

costs were 7.5 percent. Also, Mr. Kahal used a 4.86% percent rate for short-term debt instead of Southern Union's actual 2001 year-end cost of 2.83 percent in the event short-term rates rise.[125]

Addressing cost of equity issues, Mr. Kahal refused to include a flotation expense adder because Southern Union does not plan to issue new common stock. Also, Mr. Kahal rebutted Mr. Dunn's recommendation that only earnings growth rate projections should be considered and all other evidence should be ignored. In addition, Mr. Kahal noted that there is no need for a risk adjustment because ProvGas and Valley would pose less investor risk than many of the 13 comparable companies in the proxy group. Also, Mr. Kahal reaffirmed his view that Southwest Gas should be included in a proxy group.[126]

In his surrebuttal testimony, Mr. LeLash discussed non-firm margins, ESM, weather normalization and ERC recovery. For non-firm margins, Mr. LeLash reaffirmed his position that $1.6 million is an appropriate threshold for sharing non-firm margins and noted that NEGas' proposed threshold of $1.2 million has been exceeded in each of the past five years. Also, Mr. LeLash noted that NEGas will not be at risk if it does not reach the non-firm margin threshold and therefore, shareholders should receive only 25 of margins percent above the threshold. Mr. LeLash responded to Mr. Quain's criticism regarding a performance-based equity return incentive. As for the SQP, Mr. LeLash

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[125] Div. Ex. 4: (Kahal's surrebuttal testimony), pp. 5-10.

noted that NEGas' first earnings filing would not occur until the late summer of 2003, he believed there was adequate time to put a SQP into effect. Also, Mr. LeLash reasserted that the ESM should be in effect for eight years based on three years to achieve cost savings and five years for shareholders to save in incremental earnings.[127]

Regarding weather normalization, Mr. LeLash stated that the use of a deadband allocates some weather risk to the utility which is appropriate because weather normalization is for extreme temperature variations. Also, he noted the difficulties in implementing a Type I weather normalization. As for ERC recovery, Mr. LeLash stated that NEGas needed no additional incentives to pursue insurance and third party claims and therefore any recoveries should be applied 100 percent to any unamortized ERC balances.[128]

In his surrebuttal testimony, Mr. Oliver discussed rate design and tariff language. Mr. Oliver dismissed Mr. Heintz's criticism that the Division's proposal would have a more adverse impact on Valley's residential customers. Also, Mr. Oliver was not persuaded by Mr. Heintz's explanation for placing a greater than system average increase on the medium C&I class. In addition, Mr. Oliver disputed Mr. Heintz's assertion that NEGas' cost to provide gas service does not differ between transportation and firm sales customers. Furthermore, Mr. Oliver

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[126] Id., pp. 10-16.
[127] Div. Ex: 8: (LeLash's rebuttal testimony), pp. 2-8.
[128] Id., pp. 8-12.

disapproved of the allocation of transportation service costs among all of NEGas' customers.[129] In conclusion, Mr. Oliver reaffirmed his position regarding therm billing and weather normalization.[130]

V. ORIGINAL SETTLEMENT

On April 29, 2002, NEGas and the Division filed a Settlement Agreement ("Settlement") with the Commission. In the Settlement, NEGas agreed to a base-rate revenue reduction of $3.9 million on a consolidated basis as of July 1, 2002. The consolidated base-rate revenue requirement was $121,522,000, exclusive of purchased gas costs, taxes, DAC and non-base tariff revenue. In addition, the consolidated revenue requirement reflects average annual net merger-related savings of $4.099 million, with 50 percent of those savings being credited to customers. Also, the revenue requirement reflects the amortization of one-time operation and maintenance costs necessary to achieve the merger-related savings. 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.[131]

The Settlement established a one state, one rate tariff structure for Rhode Island. To mitigate the bill impacts on residential and small C&I customers in the Valley service area, a credit to the DAC will be applied

[129] Div. Ex. 6: (Oliver's surrebuttal testimony), pp. 4-14.
[130] Id., pp. 15-16.
[131] Joint Ex. 1, p. 4.

so that the average Valley residential and small C&I customer will be held harmless for the first year of rate consolidation, July 1, 2002 through June 30, 2003. The credit to Valley's DAC will be reduced by 50 percent for the second year, July 1, 2003 through June 30, 2004, after which the credit will be phased out.[132]

In the Settlement, the parties agreed to a base rate freeze period through June 30, 2005, subject only to exogenous events and changes to DAC. The Settlement defines an exogenous event as a state-initiated cost change affecting revenue by more than $350,000, or a federal-initiated cost change affecting revenues by more than $500,000. An exogenous event consists of a federal, state or local tax change or changes to federal and/or state regulatory mandates. Any exogenous event adjustment is subject to Commission review and approval. A party claiming that there should be a rate modification from an exogenous event has the burden of proof.[133] An approved exogenous event adjustment will be reflected as a debit or credit to DAC.

After the end of the rate freeze period, NEGas can file a base-rate proposal to change distribution rates or any party can file a complaint with the Commission to request a cost-of-service review to lower distribution rates. The Settlement establishes an ESM effective through June 30, 2010. The determination of earnings subject to the ESM will be based on a benchmark ROE of 11.25 percent. NEGas' imputed capital

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[132] Id., pp. 5-6.

structure is: 8.8 percent for short-term debt; 45.7 percent for long-term debt, 1.9 percent for preferred stock and 43.6 percent for common equity. To calculate the earned ROE subject to ESM, the cost of long-term debt will be 7.81 percent, the cost of preferred stock will be 9.93 percent, and the cost of short-term debt will be the most recent 12-month average cost of short-term debt for Southern Union. The ESM formula is 50/50 sharing between shareholders and ratepayers for earnings on equity between 11.25 percent and 12.25 percent. For earnings above a 12.25 percent ROE, ratepayers will receive 75 percent and shareholders will receive 25 percent.[134]

The Settlement provides for NEGas to demonstrate achieved cost savings. These savings will be included for the purposes of determining earnings subject to ESM in all years after the rate freeze period ends until July 1, 2010.[135] For non-firm margins, the threshold amount is set at $1.6 million annually. If NEGas does not recover $1.6 million, NEGas can recover the difference through DAC. Ratepayers will receive 75 percent of non-firm margins above $1.6 million.[136] The parties agreed upon a DAC which will recover costs associated with system balancing, low income assistance programs, DSM, ERC, non-firm margins, ESM, weather normalization and service quality adjustments. For weather normalization, the parties agreed on a Type 2 mechanism with a 2

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[133] Id., pp. 7-9.
[134] Id., pp. 9-13.
[135] Id., pp. 13-15.

percent deadband, as well as conversion to therm billing. The Settlement provides that ERC will be amortized over 10 years and any applicable insurance proceeds net of costs associated with obtaining such proceeds will be credited to ratepayers through DAC. The Division and NEGas set forth their intention of filing a SQP no later than December 31, 2002 for Commission review and approval.[137]

In response to a Commission data request, the Division filed supplemental testimony from David Effron to explain the Settlement Agreement, which reduced NEGas' base revenues by $3.9 million. Mr. Effron asserted that the $3.9 million reduction is reasonable within the context of the overall Settlement. Mr. Effron noted that rates are frozen for three years, and therefore, NEGas is at risk for realization of the merger savings. In addition, if the merger savings are achieved, ratepayers will benefit through the ESM for earnings above 11.25 percent. Also, Mr. Effron noted that NEGas would not be able to implement any significant rate increase after the rate freeze period without surrendering some of the shareholders' share of merger savings.[138]

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[136] Id., pp. 15-16.
[137] Id., pp. 16-19.
[138] Effron's supplemental testimony, pp. 5-9.

VI. EVIDENTIARY HEARINGS

After notice, public hearings on the Settlement were conducted at the Commission's offices, 89 Jefferson Boulevard, Warwick, from May 6, 2002 through May 9, 2002.[139] The following appearances were entered:

FOR NEGAS:	Craig Eaton, Esq. Robert Keegan, Esq.
FOR DIVISION:	Paul Roberti, Esq. Assistant Attorney General
FOR LOCAL UNION 12431:	Dennis Roberts II, Esq.
FOR GEORGE WILEY CTR:	Hugo Ricci, Esq.
FOR COMMISSION:	Steven Frias, Esq. Executive Counsel

At the May 6, 2002 hearing, the Division and NEGas presented a panel of witnesses in support of the Settlement: Mr. Kahal, Mr. Effron, Mr. Oliver and Ms. Partridge. Mr. Effron indicated that the benefits of the Settlement to ratepayers include: a $3.9 million rate reduction, a mechanism for sharing earnings above an 11.25 percent ROE, a three-year rate freeze, and an incentive to NEGas to control costs in order to retain its share of merger savings.[140] Regardless of the Settlement, counsel for the Division acknowledged that the Commission could initiate an investigation to determine if NEGas was over-earning. However, Mr. Effron maintained that an ESM is a more automatic

[139] The Commission conducted numerous public hearings to receive public comment. Prior to the filing of the Settlement, most members of the public expressed opposition to NEGas' proposed rate increase. At a public hearing following the filing of the

method of distributing over earnings to ratepayers than a formal investigatory proceeding.[141]

Mr. Kahal acknowledged that the 11.25 percent threshold for the start of ESM was the outer limit for an appropriate ROE. He also concurred that ProvGas and Valley had ROEs of 10.9 percent before the merger. Regarding short-term debt, Mr. Kahal acknowledged that prior to the merger, ProvGas had 16 percent while Valley had 11.4 percent of its capital structure consisting of short-term debt. When developing the capital structure, Mr. Kahal admitted to proposing a long-term debt ratio based on Southern Union. He acknowledged that a short-term debt ratio for the proxy group was approximately 13 percent which is higher than Southern Union's 8.8 percent. Mr. Kahal utilized a hybrid approach to capital structure utilizing a proxy group and Southern Union's actual data. He did not use Southern Union's actual capital structure because its common equity was approximately 30 percent which was too low.[142]

Mr. Kahal testified that for the short-term debt rate he utilized Southern Union's actual rate and for the long-term debt rate he utilized ProvGas' and Valley's actual, pre-merger rates. For the common equity ratio, Mr. Kahal used a proxy group approach. He admitted that

Settlement, members of Local Union 12431 and elected officials expressed opposition to approval of the Settlement.

[140] Tr. 5/6/02, pp. 36-38.

[141] Id., pp. 39, 5-51.

[142] Id., pp. 51, 54, 57-61, 74.

Southern Union's actual long-term debt and its ratio of common equity were lower than what he recommended in his testimony.[143]

Mr. Effron acknowledged that NEGas would attempt to achieve merger savings regardless of any Settlement. Mr. Effron stated that even though the rate freeze is for three years, the Settlement provided for a non-firm margin threshold of $1.6 million, the most recent year's total, instead of the five-year average of $2.1 million. Mr. Oliver argued that NEGas is entitled to some incentive for non-firm margins despite the fact that the primary factor affecting non-firm margins is how the price of gas compares to oil. Mr. Oliver concurred that if the non-firm margin threshold was set higher, then it would reduce NEGas' revenue requirement.[144] Mr. Oliver noted that under ERI II, ProvGas could not seek an annual reconciliation of non-firm margins if non-firm margins fell below the agreed upon threshold. In this Settlement, the Division agreed to an annual reconciliation for non-firm margins because without the ability to annually reconcile a deficiency, there would be additional risk to NEGas. However, Mr. Oliver also admitted that to mitigate the additional risk of not allowing an annual reconciliation for non-firm margins the Commission could give NEGas a greater percentage of margin revenue above the threshold.[145]

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[143] Id., pp. 104-105, 109-111.
[144] Id., pp. 127-129, 134-135, 142-143.
[145] Id., pp. 144-148, 161.

At the May 7, 2002 hearing, Ms. Partridge, Mr. Czekanski, Mr. Effron, Mr. Oliver and Mr. Steven Scialabba, Chief Accountant for the Division, testified as a panel. The Commission inquired at length regarding the conversion to therm billing. With regard to the weather normalization clause, Mr. Oliver indicated that Valley has no weather normalization adjustment at the present time and ProvGas did not have a weather normalization adjustment prior to ERI II.[146] Mr. Oliver stated that weather normalization clauses vary from state to state and the heating averages vary from five to thirty years. Mr. Effron noted that a longer heating average than ten years would have a higher number of heating degree days and thus NEGas would need a lower revenue requirement.[147] Mr. Oliver concurred that the deadband for ProvGas weather normalization decreased from three percent in ERI I to two percent in ERI II. He concurred that the Commission has the discretion as a matter of policy to establish the deadband. Mr. Stephen Scialabba , Chief Accountant for the Division, noted that ProvGas had experienced weather variation outside the deadband during ERI II.[148] On ERC, the Division's position was adopted in the Settlement.[149] Mr. Scialabba agreed that a period of longer than 30 days is necessary to review the DAC filing.[150]

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146 Tr. 5/7/02, p. 74.
147 Id., pp. 78-81.
148 Id., pp. 83, 83, 89-90.
149 Id., pp. 98-99.
150 Id., pp. 102-104.

At the May 8, 2002 hearing, Mr. Effron, Ms. Partridge and Mr. Czekanski testified as a panel. Mr. Effron indicated that the Division adopted NEGas' position on forecasted sales growth for the Settlement. Mr. Effron noted that the Settlement required a 50/50 sharing of merger savings despite the fact that other commissions have given ratepayers a greater share.[151] Ms. Partridge discussed the expansion of the Banner CIS system into the Valley service area and acknowledged that ProvGas has experienced some problems with the Banner CIS system. Mr. Effron stated that any additional revenue expense caused by billing problems should not be passed on to ratepayers. He also stated that it was possible for a facility to be used but not useful if the facility had such poor performance.[152]

At the May 9, 2002 hearing, Mr. Oliver, Mr. Czekanski, Mr. Heintz, and Ms. Partridge testified as a panel. Mr. Oliver explained that the Settlement reflects moderation of NEGas' positions on customer charges to residential and small C&I customers, a return to existing ProvGas rate blocking, and a DAC adjustment for Valley customers. Mr. Oliver also noted that the Settlement provides for a smaller proportionate decrease in the revenue requirement from residential customer class than the large and extra large C&I customer classes because some $150,000-$200,000 of the revenue requirement was shifted to the latter classes. In addition, he stated that the Settlement allocates several hundred

[151] Tr., 5/8/02, pp. 9-10, 13-14.

thousand dollars of costs, directly attributable to transportation, to all customers.[153]

Mr. Oliver acknowledged that according to the NEGas' record response, with two exceptions, the medium, large and extra large C&I classes for Valley and ProvGas will experience rate decreases of approximately 11 to 25 percent. He also acknowledged that according to the NEGas' record response, ProvGas residential heating customers will receive approximately a 7 percent reduction while Valley residential heating customers will receive less than a 1 percent reduction for the first year. In addition, he noted that in the second and third years there will be a rate increase for the Valley residential heating customers. Furthermore, he noted that the Commission has considerable discretion in allocating costs among the various rate classes.[154]

During the May 9th hearing, the Commission expressed concern that the Settlement did not appear to require NEGas to maintain its commitments under the ERI settlements to replace 7-10 miles of gas mains per year, and issued a record request to NEGas. In its response to the Commission's record request, NEGas confirmed its commitment to "a program of mains and services replacement that requires the

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[152] Id., pp. 26, 33-34, 36-37.
[153] Tr. 5/9/02, pp. 27-29, 36, 45.
[154] Id., pp. 47, 55-57.

replacement of up to 21 miles over the three-year rate freeze period in the Settlement Agreement."[155]

As a result of concerns expressed by the Commission at the hearings, on May 14, 2002, NEGas and the Division submitted an amendment to the Settlement. The proposed amendment contained three provisions. The first provision, relating to the recovery of the ERC in the DAC, limited any increase in the ERC factors to no more than $0.01 per therm in any annual DAC filing. The second provision, relating to a SQP, required that it contain a system of penalty and penalty-offset adjustments similar to the SQP for Narragansett Electric. The third provision, relating to joint and common cost allocation, required NEGas to allocate common costs with Southern Union on terms no less favorable than those applied in other jurisdictions wherein Southern Union operates as a regulated utility.[156]

VII. MAY 15, 2002 OPEN MEETING

On May 15, 2002, the Commission conducted an open meeting to review the evidence presented and consider the Settlement as amended on May 14, 2002, ("Amended Settlement"). Chairman Germani expressed support for the Amended Settlement noting that, to a great extent, it reflected the position of the Division, which represents the ratepayers. In addition, Chairman Germani opined that the Amended Settlement between NEGas and the Division was more favorable to the ratepayers

[155] NEGas response dated May 14, 2002 to Commission Record Request of May 9, 2002.

than the Narragansett Electric merger settlement that had been approved previously by the Commission.[157]

Commissioner Racine did not express support for the Amended Settlement because she believed that it did not go far enough in benefiting ratepayers. She expressed particular concern regarding the rate impacts on Valley's customers. Commissioner Racine noted that the Division's surrebuttal position would result in a $7.5 million revenue reduction. She also noted that in addition, NEGas' shareholders could receive a smaller share of merger savings, the non-firm margin revenue could be set at $2.1 million, a 20 year heating average could be used for setting revenues, the dead band for weather normalization could be set at 3 percent, and the cost of capital could be modified in regards to ROE. Commissioner Racine estimated that these modifications could reduce NEGas' revenue requirements by $11.5 million. In conclusion, Commissioner Racine recommended litigation of the rate case.[158]

Commissioner Gaynor indicated support for the Division's surrebuttal position of a $7.5 million revenue reduction. In addition, Commissioner Gaynor noted that ERC and possibly other items like LNG system balancing, which were included in DAC under the Amended Settlement, could be included in base rates instead. Also, Commissioner Gaynor favored reducing the amortization period for the Banner CIS

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[156] Amendment to Settlement Agreement, pp. 1-2.
[157] Tr. 5/15/02, pp. 6-11.
[158] Id., pp. 11-19.

system from 18 years to 10 years and reducing the amortization period for the Y2K balance from 15 years to 10 years. Furthermore, Commissioner Gaynor expressed interest in reducing the ROE to 10.75 percent, and increasing the percentage of short-term debt in the capital structure. Also, Commissioner Gaynor stated that ratepayers could receive 75 percent of merger savings and that the non-firm merger revenues could be set at $2.1 million with no annual reconciliation. Commissioner Gaynor favored the use of a 10-year heating average but would also increase the dead band to 5 percent for weather normalization.[159] At the conclusion of the open meeting, Commissioner Gaynor moved that the Amended Settlement with her proposed modifications be submitted to NEGas for adoption. The motion was seconded by Chairman Germani for the purpose of giving NEGas the opportunity to accept the proposed modifications. The motion was adopted with Commissioner Racine dissenting.[160]

VIII. MAY 20, 2002 OPEN MEETING

On May 17, 2002, NEGas filed a letter with the Commission requesting clarification regarding the modifications to the Amended Settlement proposed by Commissioner Gaynor at the May 15th open meeting. On May 20, 2002, the Commission conducted another open meeting at which Commissioner Gaynor indicated that there should be a $7.5 million revenue reduction based on the Division's surrebuttal

[159] Id., pp. 19-35.

position and that the ESM would begin at 10.75 percent. Also, Commissioner Gaynor stated ERC recovery should be included in base rates and thus, an additional $1.2 million per year should be included in base rates. Also, Commissioner Gaynor indicated that non-firm margins should be set at $2.1 million and that shareholders should receive 50 percent of revenues above this threshold.[161]

IX. NEGAS MAY 22, 2002 FILING

On May 22, 2002, NEGas filed a letter with the Commission in response to the May 20th open meeting. At the outset, NEGas stated it would not accept the proposed modifications to the Amended Settlement. NEGas stated it could not agree to a rate reduction greater than $3.9 million. Also, NEGas maintained that the Amended Settlement has significantly more benefits for customers than the Narragansett Electric merger settlement. NEGas argued that a revenue reduction greater than $3.9 million will necessitate substantial workforce reductions in the near term and undermine NEGas' ability to maintain its capital-investment programs and detrimentally affect customer service. Regarding the DAC, NEGas expressed a willingness to transfer recovery of ERC, low-income programs, weatherization and DSM to base rates if there is an annual reconciliation mechanism. However, NEGas asserted that the costs of LNG system-pressure maintenance should remain in the DAC because

[160] Id., pp. 43-46, 51-52.
[161] Tr. 5/20/02, pp. 2-5.

all NEGas customers benefit from it and the cost varies with gas commodity prices.[162]

NEGas stated it would be willing to shorten the amortization period for the Banner CIS system and Y2K costs if the revenue reduction was reduced by $729,000. As for the ESM, NEGas noted that the ESM in the Amended Settlement provides ratepayers with earnings sharing after 11.25 percent ROE while the ESM in the Narragansett merger settlement provides for earnings sharing after 12.00 percent ROE. In regards to non-firm margins, NEGas stated that $2.1 million is not realistic and it would accept its imputation into base rates only if non-firm margins were fully reconcilable. NEGas opposed any reduction in its shareholders' portion of merger savings and noted that in the Narragansett merger settlement there was a 50/50 sharing between ratepayers and shareholders. NEGas asserted that a 5 percent weather normalization deadband would render it ineffective and thus was unacceptable. Regarding the SQP, NEGas stated it would file a SQP no later than September 30, 2002 linking NEGas' quality of its customer service to NEGas' ability to participate in the ESM. In addition, NEGas stated it would waive account restoration charges and return-check fees for customers eligible for low-income assistance programs.[163]

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[162] NEGas's letter dated 5/22/02, pp. 1-2, 6-10.

X. MAY 23, 2002 OPEN MEETING

On May 23, 2002, the Commission conducted another open meeting to discuss NEGas' proposed modifications to the Amended Settlement as outlined in its May 22, 2002 letter to the Commission. Commissioner Gaynor also explained her concern that when the costs for the DAC items are included with the base revenues the result appeared to be a rate increase instead of a rate decrease of $3.9 million.[164]

XI. MAY 23, 2002 HEARING

Following the open meeting on May 23, 2002, NEGas and the Division filed a joint motion requesting an immediate hearing to respond to the comments made at open meeting and to seek approval of the Amended Settlement. Specifically, the parties sought an opportunity to address Commissioner Gaynor's concern that the Amended Settlement will result in an overall revenue increase to ratepayers. The parties stressed the need for an immediate hearing before any inaccuracies were communicated by the media to the public. In support of their position that the Settlement provided for an overall revenue reduction of $3.9 million, an affidavit by Ms. Partridge was included.[165]

The Commission granted the request for hearing and reconvened on May 23, 2002. Attorney General Sheldon Whitehouse made public comment. He expressed support for prompt acceptance of the Amended

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[163] Id., pp. 10-12,
[164] Tr. 5/23/02, pp. 6, 10-14.
[165] Joint Motion of NEGas and the Division for a hearing.

Settlement.[166] Ms. Partridge testified that NEGas is currently collecting approximately $129,000,000 in non-gas costs and that the $3.9 million reduction will reduce NEGas' revenues to approximately $125 million. Ms. Partridge stated that the $3.9 million reduction is to non-gas costs, and non-gas costs include DAC and base rates.[167] Also, the Division expressed opposition to an amendment to the Settlement that included a reduction in the amortization period for the Banner CIS system and Y2K costs because it would reduce the $3.9 million reduction to approximately $3.2 million.[168]

XII. MAY 23, 2002 BENCH DECISION

Immediately following the May 23rd hearing, the Commission proceeded at the bench to discuss and vote upon the Amended Settlement and proposed modifications to it. On the first proposed amendment to link NEGas' quality of service to its ability to participate in the ESM, the Commission voted unanimously to approve the amendment. A majority of the Commission, Chairman Germani and Commissioner Racine, voted not to include an amendment that would reduce the amortization period for the Banner CIS system and Y2K costs. On the third amendment, to waive account-restoration charges and return check fees for customers eligible for low-income assistance programs, the Commission voted unanimously to approve the

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[166] Tr. 5/23/02, p. 6.
[167] Id., pp. 21-22, 27.
[168] Id., p. 51.

amendment.[169] A majority of the Commission, Commissioners Racine and Gaynor, voted to adopt the first paragraph of the fourth proposed amendment which would include ERC, low-income program costs, weatherization program costs, and DSM costs in base rates (rather than DAC), subject to an annual reconciliation. A majority of the Commission, Chairman Germani and Commissioner Racine, voted to adopt the second paragraph of the fourth proposed amendment which established the DAC for reconciling ESM, LNG for maintaining system pressures, weather normalization, and for refunding or recovering the amount by which non-firm margins deviate from $1.6 million on an annual basis.[170] A majority of the Commission, Chairman Germani and Commissioner Racine, approved the Amended Settlement with all previously adopted amendments.[171]

XIII. COMPLIANCE FILING

On June 14, 2002, NEGas made a compliance filing. This filing included a Final Amended Settlement as well as supporting rates and tariff provisions.[172] On June 21, 2002, the Commission conducted a public hearing, in part, on the compliance filing. The Division indicated that the Final Amended Settlement reflected the Commission's bench decision of May 23, 2002. Also, the Division stated that the proposed

[169] Id., pp. 56-58.
[170] Id., pp. 58, 69-70, 77-78.
[171] Id., p. 82.
[172] The Final Amended Settlement is attached as Appendix A and is hereto incorporated by reference herein.

rates appeared accurate. However, the Division expressed concern over the wording of the DAC tariff provision relating to on-system credits and the margin sharing. Accordingly, the Commission approved the compliance filing on an interim basis.[173]

On July 26, 2002, Mr. Oliver submitted pre-filed testimony recommending approval of the compliance filing including modifications to paragraph 3.5 in Section 3 of the NEGas tariff entitled "Distribution Adjustment Charge". Specifically, Mr. Oliver recommended the tariff be revised to provide that if the total non-firm margins exceed $1.6 million, the On-System Credit shall be 75 percent of the amount in excess of $1.6 million, while if the non-firm margins are less than $1.6 million, the On-System Credit shall be negative.[174] In other words, if the credit is positive, ratepayers will receive funds but if the credit is negative, NEGas will be entitled to funds. On August 19, 2002, NEGas filed a motion requesting final approval of the compliance filing as amended by the Division. The Division supported the motion. At an open meeting on August 28, 2002, the Commission unanimously approved the amended compliance filing.

COMMISSION FINDINGS

When reviewing a proposed settlement, the Commission weighs the benefits to the ratepayers with the interests of the utility. The objective of the Commission is to set rates that are in the public interest. The

[173] Tr. 6/21/02, pp. 68-69, 79-81.

Commission finds that the Final Amended Settlement appropriately balances the interests of the ratepayers with the utility's interests and is in the public interest.

First, the Final Amended Settlement provides for an immediate $3.9 million revenue reduction, which will total $11.7 million over three years. Ideally, the Commission would prefer to have the largest immediate rate reduction possible, but NEGas cautioned that a larger up-front reduction would have required workforce reductions that would negatively impact NEGas' quality of service. Additionally, the proposal of the parties to use a credit to DAC as a means to gradually phase-in a unified rate structure for Valley customers is innovative and avoids a primary concern of the Commission which is rate shock.

Secondly, the Final Amended Settlement freezes distribution rates for a three-year period, through June 30, 2005. As a result, ratepayers will not only receive an immediate rate reduction, but will also maintain the benefit of this lower rate for a significant period of time.

The Commission expressed concern regarding DAC, specifically that ERC could necessitate large rate increases. Under the Final Amended Settlement, annual increases in the ERC factor are limited to no more than $0.01 per therm annually. In addition, to mitigate the magnitude and volatility of periodic DAC adjustments which are likely to occur as a result of ongoing expenditures for ERC and items such as

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[174] Oliver's pre-filed testimony dated 7/26/02, pp. 2-5.

DSM and low-income programs, the parties agreed to include a pre-determined portion of the costs of ERC and other such items in base rates, while establishing DAC as an annual reconciliation mechanism for downward or upward adjustments of ERC and other such items. By including a portion of those costs in base rates, DAC adjustments due to ERC and other DAC-related items will presumably account for a small percentage of a NEGas' ratepayer's total bill.

In the area of ESM, it is apparent that the Final Amended Settlement for NEGas is in the best interest of the ratepayers. Earnings sharing on a 50/50 basis begins when NEGas' ROE is 11.25 percent. Also, a 75/25 split in favor of the ratepayers for earnings sharing occurs when NEGas' ROE is 12.25 percent. Moreover, the calculation for determination of ESM is done on an annual basis for NEGas.

The Final Amended Settlement for NEGas has reasonable procedures and standards for determining merger savings after the rate freeze period. This is an effective tool for keeping rates down, placing the burden upon the utility to prove its merger savings.

As for service quality, the Final Amended Settlement for NEGas lacks a SQP and the Commission expressed concern over this deficiency. The parties addressed this issue by committing to file, in the near future, a SQP with penalties that will link NEGas' participation in the ESM to the quality of its service. Without this commitment, the Commission would have been hesitant to of approve any settlement. The Commission looks forward to quickly reviewing and ordering a SQP that ensures customers will receive excellent service.

As for non-firm margins and the weather normalization clause, the Commission's objective is to adopt a policy that fairly distributes risk between ratepayers and shareholders over a three-year rate freeze. The Final Amended Settlement's provision for non-firm margins of $1.6 million reflects the original pre-filed position of the Division. Also, it is difficult to predict what non-firm margins will be over the three-year rate freeze period; therefore, an annual reconciliation provision for non-firm margins avoids placing undue risk on NEGas. The Final Amended Settlement's provision for a 2 percent deadband for weather normalization is to some extent consistent with the concept that weather normalization should only be utilized for abnormal weather conditions. The Final Amended Settlement for NEGas also has appropriate procedures and standards for determining exogenous events.

In addition, while the Commission could have reduced the amortization period for the Banner CIS system and Y2K costs, this would have resulted in reducing the revenue reduction from $3.9 million to $3.2 million. A smaller immediate reduction in base revenues would have made it more difficult to avoid a rate shock for Valley customers once rates are unified. Accordingly, the Commission cannot support a reduced amortization under these financial circumstances.

The Commission is pleased that NEGas has agreed to waive the account-restoration and returned check fees for low-income ratepayers. The plight of low-income individuals is a difficult issue to adequately address, but in this docket the Commission has attempted to assist low-income families by waiving these fees in conjunction with a $3.9 million rate reduction.

The Commission is also pleased that NEGas has committed to replacing 21 miles of cast-iron and bare steel mains and services over the three-year rate freeze period. A large percentage of NEGas' distribution system consists of aging mains and services installed decades ago. An infrastructure replacement program is essential to the viability and safety of NEGas' system.

Finally, the Commission observes that it could have rejected the Final Amended Settlement and instead have pursued litigation of this rate case. Litigation of this rate case could have possibly resulted in a greater rate reduction, perhaps more than $11 million in one year. Overall, the Final Amended Settlement may not be perfect but it is in the best interest of NEGas' ratepayers and in the public interest because it reduces rates by $11.7 million over three years and freezes distribution rates over the same time period.

Accordingly, it is

(17381) ORDERED:

1. The rate plan filed on November 1, 2001 relating to the consolidation of Providence Gas Company and Valley and Bristol & Warren Gas Companies is hereby denied and dismissed.

2. The following modifications to the Amended Settlement are hereby approved:

   a. New England Gas Company will file, no later than September 30, 2002, a proposed Service Quality Plan that will link New England Gas Company's quality of service to its ability to participate in the earnings-sharing mechanism.

   b. New England Gas Company will waive its account-restoration charges and returned-check fees for customers eligible for low-income assistance programs.

   c. New England Gas Company will include the following in base rates, subject to an annual reconciliation of the amount embedded in base rates to actual expenditures: (i) Environmental Response Costs at $1.31 million; (ii) Low Income Program Costs at $1.585 million; (iii) Weatherization Program Costs at $200,000; and (iv) Demand-Side Management Costs at $300,000; and the $3.9 million reduction to base rates is adjusted to reflect the annual impact of transferring these items from the Distribution Adjustment Charge to base rates.

d. New England Gas Company will establish a Distribution Adjustment Charge for the purposes described in the Amended Settlement, including but not limited to: crediting customers with any amounts associated with the earnings-sharing provisions of the Amended Settlement; refunding or recovering the amount by which non-firm margins deviate from $1.6 million; recovering LNG commodity costs associated with maintaining system pressures; crediting or collecting of any weather normalization adjustment revenues, and any other reconciliation of revenues or expenses approved by this Commission.

3. The Settlement filed on April 29, 2002, as amended by the parties' filing of May 14, 2002, and as further modified by paragraphs 9(a)-(d) of Ordering paragraph No. 2 of this Report and Order, is hereby approved.

4. The compliance filing of June 14, 2002, including the Final Amended Settlement and supporting rates and tariffs as amended by New England Gas Company's filing of August 19, 2002, is hereby approved.

EFFECTIVE JULY 1, 2002 AT WARWICK, RHODE ISLAND PURSUANT TO A BENCH DECISION ON MAY 23, 2002 AND AN OPEN MEETING DECISION ON AUGUST 28, 2002. WRITTEN ORDER ISSUED FEBRUARY 28, 2003.

PUBLIC UTILITIES COMMISSON

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Elia Germani, Chairman*

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Kate F. Racine, Commissioner

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Brenda K. Gaynor, Commissioner*

*Chairman Germani concurs except with Ordering Paragraph 2(c).

*Commissioner Gaynor concurs except with Ordering Paragraphs 2(d) and 3.

Concurring Opinion of Chairman Germani:

I believe that I should address in some detail the reasons why I concur with respect to the approval of the Final Amended Settlement as set forth in the Ordering Paragraph 3. As I stated in the Open Meeting on May 15, 2002 I was supporting the Amended Settlement because it, to a great extent, reflected the position of the Division, which is obligated by statute to represent the ratepayers. I also stated that I believe that the Amended Settlement between NEGas and the Division was more favorable to the ratepayers than the Narragansett Electric Company Merger Settlement that had been previously approved by the Commission. Although prior settlements are not precedent, they provide guidance to future Commissioners in utilizing their ratemaking authority. In the present merger rate case, I looked to the recent Narragansett Electric merger rate case for enlightenment.

In regard to an immediate rate reduction, the Final Amended Settlement has a $3.9 million revenue reduction while the Narragansett Electric merger settlement had a $13.1 million reduction. However, it should be stated that the Narragansett Electric reduction included overearnings for Blackstone Valley Electric (BVE) and Newport Electric. Also, the cost of service for Narragansett Electric was approximately $82 million more than NEGas' cost of service and, therefore, proportionally the rate reduction would be larger.

Certainly, I would have preferred the largest immediate rate reduction possible but NEGas stated that a large reduction would have required workforce reductions thus negatively impacting the quality of service. Also, the proposal of the parties to use a credit in the DAC as a means to gradually phase-in a unified rate structure for BVE customers is innovative and avoids a primary concern of the Commission, which is rate shock.

Not only is there an immediate rate reduction, but a base rate freeze is provided for in the Final Amended Settlement. As a result, ratepayers receive an immediate rate reduction and will maintain this lower rate for a significant period of time. The Final Amended Settlement provided for a base rate freeze of three years. While the Narragansett Electric Settlement had a base rate freeze for over four years, it should be noted that under the Merger Settlement for Narragansett Electric, Narragansett could seek a rate increase during the freeze period if inflation exceeded a certain level.

The Final Amended Settlement for NEGas and the Narragansett Electric Settlement has comparable procedures and standards for determining exogenous events. The only significant difference is that the threshold amount for determining if an exogenous event occurred is lowered in regard to total dollar amounts.

In the area of earnings share mechanism (ESM) it is apparent that the Settlement for NEGas is comparable to, if not better than, the ESM in place as a result of the Narragansett Electric Merger Settlement. NEGas ratepayers' earnings sharing come when the Return on Equity (ROE) is 11.25% or higher on a 50/50 basis with the shareholders while the Narragansett ratepayers received the benefit only when the ROE was 12% or higher. Similarly, a 75/25 spread in favor of the ratepayers for earnings occurs when the ROE is 12.25% or higher for NEGas while it is 13% or higher for Narragansett. Almost as important is that the calculation for determination of ESM is done on an annual basis for NEGas while for Narragansett it is done on the basis of the entire rate freeze period. Accordingly, it is more likely that NEGas ratepayers will participate in the ESM than Narragansett ratepayers.

The Settlement for NEGas and the Narragansett Electric Company Merger Settlement have effective procedures and standards for determining merger savings after the rate freeze period. This is an effective tool for keeping rates down and placing the burden upon the utility to prove its merger savings.

Elia Germani

COMMISSIONER GAYNOR:

I disagree with Chairman Germani's comparative use of the rate settlement reached three years ago in the Narragansett Electric merger rate case to bolster support for the rate settlement approved in the instant New England Gas merger rate case. A comparison of the benefits produced by these two very different settlements reached with two very different utilities is simply not meaningful for the purpose of determining whether the New England Gas settlement is in the best interest of ratepayers. But if the relative benefits of the two settlements are to be compared, it must be pointed out that the *Narragansett Electric* rate settlement of 2000 provided its ratepayers with a significantly larger up-front rate reduction when compared to the utilities' respective costs of service, a significantly longer distribution rate freeze period (nearly 5 years, to New England Gas' 3 years), a favorable resolution of the investigation into the over-earnings of Newport Electric Company (New England Gas' earnings under the ERI-2 settlement are still in dispute), and reductions by Narragansett Electric to a number of outstanding liabilities that would otherwise be recoverable from ratepayers.

Also, Narragansett Electric's distribution rate freeze is truly a base rate freeze, that is to say, except for the ability to seek rate relief for a limited number of well-defined exogenous events, Narragansett Electric's base distribution rates cannot be changed for nearly 5 years, regardless of changes in its underlying cost of service. Under the New England Gas settlement, however, a novel "Distribution Adjustment Clause" has been created to enable New England Gas to pull out various cost items, such as environmental remediation costs and weather normalization revenues, from base distribution rates and to pass through increases or decreases in these distribution costs, which are likely to be significant, to ratepayers on an annual basis.

Finally, it must be pointed out that due to the combined benefits of a long-term fixed price schedule for standard offer energy rates and the distribution rate freeze implemented by the rate settlement, Narragansett Electric's ratepayers have experienced and should continue to experience relatively stable electric rates. The same cannot be said for New England Gas' ratepayers who, notwithstanding the distribution rate freeze, will continue to be subject to rate fluctuations resulting from the periodic reconciliation and pass-through of New England Gas' purchased gas costs, which continue to be subject to extreme price volatility and uncertainty, and additional distribution costs passed through to ratepayers under the Distribution Adjustment Clause.