BEFORE THE
PUBLIC UTILITIES COMMISSION
OF THE
STATE OF RHODE ISLAND
AND PROVIDENCE PLANTATIONS

IN THE MATTER OF

The New England Gas Company	**)**	
Proposal For Changes In Its	**)**	**Docket No. 3548**
Distribution Adjustment Charge	**)**	

DIRECT TESTIMONY OF WITNESS
BRUCE R. OLIVER

On Behalf of

The Division of Public Utilities

October 8, 2004

TESTIMONY OF BRUCE R. OLIVER
Docket No. 3548
October 8, 2004

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS FOR THE RECORD.

A. My name is Bruce R. Oliver. My business address is 7103 Laketree Drive, Fairfax Station, Virginia, 22039.

Q. BY WHOM AND IN WHAT CAPACITY ARE YOU EMPLOYED?

A. I am employed by Revilo Hill Associates, Inc., and serve as President of the firm. I manage the firm's business and consulting activities, and I direct its preparation and presentation of economic, utility planning, and policy analyses for our clients.

Q. ON WHOSE BEHALF DO YOU APPEAR IN THIS PROCEEDING?

A. My testimony in this proceeding is presented on behalf of the Division of Public Utilities (hereinafter "the Division").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. This testimony addresses the request of New England Gas Company (hereinafter "NEG" or "the Company") for a change in its Distribution Adjustment Charge ("DAC") which is set forth in testimony filed on July 30, 2004 and September 3, 2004 by witness Peter C. Czekanski on behalf of the Company. More specifically, this testimony discusses all elements of the Company's DAC calculations other than the Earnings Sharing Mechanism. Issues relating to Earnings Sharing for the 12 months ended June 30, 2004 will be addressed in subsequent testimony that is scheduled to be filed by Division witness David Effron.

Q. HAVE YOU PREVIOUSLY TESTIFIED IN THIS DOCKET?

A. Yes. I testified for the Division regarding NEG's non-earnings sharing DAC calculations for the fiscal year ended June 30, 2003.

Q. WHAT ARE THE MAJOR COMPONENTS OF THE COMPANY'S DISTRIBUTION ADJUSTMENT CHARGE (DAC) CALCULATIONS?

A. NEG's proposed DAC calculations comprise nine (9) major components. The components of the Company's Distribution Adjustment Charge calculations include:

1. A System Pressure (SP) Factor
2. A Demand Side Management (DSM) Factor
3. A Low Income Assistance Program (LIAP) Factor
4. An Environmental Response Cost (ERC) Factor
5. An On-System Margin Credits (MC) Factor
6. A Weather Normalization (WN) Factor
7. An Earnings Sharing Mechanism (ESM)
8. A Reconciliation (R) Factor
9. An Allowance for Uncollectibles

The first eight components of the Company's DAC calculations are re-examined, and subject to re-calculation on an annual basis. The last component (i.e., the Allowance for Uncollectibles), was established through the Commission-approved settlement in Docket No. 3401. The Reconciliation (R) Factor includes adjustments for over- or under-recovery of costs during the 12-months ended June 30, 2004 for each of the first eight factors listed above, as well as the previous reconciliation factor and remaining ERI-2 adjustments (which apply only to customers in former Providence Gas Company service territory). NEG's proposed calculations for each of the components of the DAC are reviewed below.

System Pressure Factor

Q. WHAT IS THE PURPOSE OF THE SYSTEM PRESSURE ADJUSTMENT?

A. Since the beginning of rate unbundling for firm service customers, the Commission has recognized that a portion of the Company's use of its LNG facilities is associated with the maintenance of operating pressures on its system. Given that both sales service and transportation service customers benefit from the maintenance of system operation pressures, it is appropriate that such costs be recovered from customers in both of those service classifications. However, in the absence of the System Pressure Adjustment, all of the Company's LNG costs would be recovered through its Gas Cost Recovery (GCR) charges. Thus, it is necessary for the Company to allocate a portion of its LNG costs to system pressure maintenance, and collect those costs through charges that are applied to both firm sales service and firm transportation service customers. The System Pressure factor within the DAC mechanism accomplishes this objective.

Q. HOW IS THE SYSTEM PRESSURE FACTOR DETERMINED?

A. As established in Docket No. 3401, the System Pressure factor is computed by multiplying Total LNG Commodity Related Costs by the System Balancing Factor (.2039) and dividing by projected, weather-normalized, annual Firm Throughput. The .2039 factor reflects the results of an assessment which suggested that 20.39% of LNG commodity related costs were used for System Pressure purposes, and therefore, should be borne by all customers (i.e., sales and transportation service customers) who utilize the Company's distribution system.

Q. HOW HAVE NEG'S CALCULATED SYSTEM PRESSURE COSTS CHANGED SINCE ITS LAST DAC FILING IN SEPTEMBER 2003?

A. The Company's System Pressure Factor for the last year was $0.0496 per dekatherm (Dth). Attachment PCC-3 to Mr. Czekanski's testimony filed July 30, 2004 computes a System Pressure factor of $0.0538 per Dth. The calculations underlying that factor were subsequently updated in Mr. Czekanski's September 3, 2004 Revised Attachment PCC-3. As updated, NEG seeks a System Pressure

Factor of $0.0564 per Dth. Thus, the Company's revised System Pressure Factor calculations yield a charge per Dth that is $0.0068, or 13.7% above the result from comparable calculations made just one year ago. However, that increase in System Pressure costs appears to be driven primarily by a substantial increase in LNG Withdrawal Commodity costs which NEG projects will rise from a projected level of $4,517,774 for the 12 months ended October 2004[1] to a projected level of $5,947,231 for the 12 months ended October 2005.[2] Moreover, the resulting increase of $1,429,457 (or **31.6%**) in the Company's projected LNG Withdrawal Commodity costs is driven primarily by an increase in NEG's projected use of LNG in January 2005 relative to the LNG use that NEG had projected for the same month of the prior year.

I also observe that while the Company's projected use of LNG for the coming winter has increased significantly, its projected average cost of LNG on a dollars per Dth basis has declined from the prior year. For the 12 months ended October 2004, NEG projected an average LNG Withdrawal Commodity cost of $8.29 per Dth. For the 12 months ended October 2005, the Company's projected LNG Withdrawal Commodity cost is $7.87 per Dth. Thus, the Company's forecasted costs for the coming GCR period reflect a decrease of $0.43 per Dth (or -5.1%) in its

[1] NEG's September 2, 2003 filing in this docket, Revised Attachment PCC-3.

[2] NEG's September 3, 2004 filing in this docket, Revised Attachment PCC-3.

LNG Withdrawal Commodity costs, despite a significant increase in projected pipeline commodity costs. In addition, NEG's projected LNG Inventory costs and LNG Demand costs for the 2004-05 GCR period are also projected to decline slightly from the levels projected for the prior year. Thus, the Company's overall increase in its projected LNG costs is directly attributable to its increased use of LNG. (See the analysis presented in Schedule BRO-1 attached hereto).

Q. IS THE COMPANY'S REVISED SYSTEM PRESSURE FACTOR APPROPRIATELY COMPUTED?

A. The Company's calculation of its revised System Pressure Factor computations appear to be mathematically accurate and performed in a manner consistent with NEG's tariff. However, the significant increase projected in January LNG use appears to reflect a change in the Company's economic dispatch of LNG, and such a change in the economic dispatch of LNG may undermine the assumptions relied upon to support the Company's assessment in Docket No. 3401 that 20.39% of LNG costs could be associated with the maintenance of system pressures. If NEG's use of LNG has changed due to economic dispatch considerations, then the proportion of LNG used for maintenance of system pressures may decline as a percentage of total LNG commodity related costs. That, in turn, would suggest the need for a change in the System Balancing factor to ensure that NEG's transportation service customers are not required to bear costs that should more appropriately be the responsibility of sales service customers. Given the magnitude of the increase in NEG's projected LNG costs and apparent changes in its dispatch of LNG relative to other sources of supply, it is possible that most, if not all, of the Company's increased LNG costs may be more appropriately recovered through its Gas Cost Recovery (GCR) charges.

Q. HOW SHOULD THE COMMISSION ADDRESS THE APPARENT CHANGE IN NEG'S USE OF LNG AND ITS IMPACTS ON THE COSTS OF MAINTAINING SYSTEM PRESSURES?

A. I recommend that the Commission recognize that NEG has computed the System Pressure factor in accordance with its tariff and agreements reached in Docket No. 3401 and permit that factor to be implemented as proposed. However, I also suggest that the Commission require NEG to track its LNG use over the next winter and provide an assessment of the impacts of changes in its LNG dispatch on the determination of the System Balancing factor and its System Pressure costs prior to the time of its next annual Distribution Adjustment Charge (DAC) filing.

<u>Demand Side Management Factor</u>

Q. WHAT IS THE PURPOSE OF THE DEMAND SIDE MANAGEMENT FACTOR?

A. The Demand Side Management factor provides the Commission a mechanism for adjusting NEG's DSM funding outside the context of a base rate proceeding.

Q. WHAT IS THE LEVEL OF FUNDING CURRENTLY PROVIDED FOR DSM PROGRAMS THROUGH THE COMPANY'S BASE RATES?

A. As set forth in NEG's tariff, Section 3, Distribution Adjustment Charge, Schedule A, Sheet 3, paragraph 3.2, the DSM funding presently embedded in base rates for the Company is **$301,496** per year. In addition, the Company projects an accrued balance of unexpended DSM funds totaling $1,007,000 that will be carried over from FY 2004 to FY 2005. Thus, the total funds available for DSM programs during FY 2005 will be approximately $1,308,000 or more than four (4) times the annual level of funding that the Commission provides NEG for such programs through its base rates.

Q. HOW MUCH DID NEG ACTUALLY EXPEND FOR DSM PROJECTS IN FY 2004?

A. The Company's response to Division Data Request 1-03 indicates that NEG had $701,200 of actual DSM disbursements in the 12-month period ended June 30,

2004. Of those expenditures, $700,000 was for the installation of a cogeneration unit by one large industrial customer. The remaining $1,200 represents the rebates provided to 12 residential customers (apparently $100 each) for the installation of high efficiency gas heating equipment.

Q. WHAT DSM EXPENDITURES DOES NEG CURRENTLY ANTICIPATE FOR THE 12-MONTH PERIOD ENDING JUNE 30, 2005?

Page 2 of the Company's response to Division Data Request DIV 1-03 indicates that NEG estimates potential DSM rebates totaling $873,400 for the 12 months ending June 30, 2005. That estimate comprises:

1	Cogeneration Unit	$500,000
2-3	Microturbines	$200,000
20	Residential Conversion Rebates	$ 2,000
4-5	Chillers and NGV Stations	$171,400
Total		$873,400

Q. ARE THE DSM FUNDS AVAILABLE TO NEG FOR FY 2005 ADEQUATE TO MEET ITS ANTICIPATED REQUIREMENTS?

A. At this point, it appears that they are more than adequate. Based on estimated FY 2005 DSM expenditures, the Company projects it will end FY 2005 with an unexpended DSM funds balance of $433,600. However, as Mr. Czekanski notes at page 6 of his July 30, 2004 testimony in this docket, NEG, as a participant in the Rhode Island Greenhouse Gas (RI GHG), is currently considering some additional DSM programs. At present no cost estimates are available for such potential additional programs, although Mr. Czekanski indicates that NEG is designing those programs to stay within current annual funding levels. In this context, the current anticipated DSM carry-over to FY 2006 (i.e., $433,600) appears reasonable.

On the other hand, if anticipated expenditures for FY 2005 do not materialize and new DSM programs remain within current annual funding levels, the Commission may wish to cap the amount of DSM funding that is carried-over to subsequent years, and provide credits through the DSM for any excess carry-overs. For example, the Commission might decide that three or four times the amount of annual DSM funding provided through base rates represents a reasonable cap on DSM funding accruals, and any balance of carry-forwards in excess of that level should be refunded to NEG customers through the DAC mechanism (i.e., a negative DSM factor). If the level of annual DSM funding authorized by the Commission is adjusted (either increased or decreased) the cap on carry-forward amounts could be adjusted accordingly.

<u>Low Income Assistance Program Factor</u>

Q. WHAT IS THE PURPOSE OF THE LOW INCOME ASSISTANCE PROGRAM (LIAP) FACTOR?

A. The Low Income Assistance Program (LIAP) factor performs a function similar to that of the DSM factor. It provides a mechanism for the Commission to adjust the funding of the Company's Low Income Heating Assistance Program (LIHEAP) and Low Income Weatherization Program activities outside the context of a base rate proceeding.

Q. WHAT IS THE LEVEL OF FUNDING CURRENTLY PROVIDED FOR NEG'S LOW INCOME ASSISTANCE PROGRAMS THROUGH ITS BASE RATE CHARGES?

A. As set forth in NEG's tariff, Section 3, Distribution Adjustment Charge, Schedule A, Sheet 4, paragraph 3.3, the LIAP funding presently embedded in base rates for NEG is **$1,793,901** per year.

Q. WHAT WAS THE TOTAL OF NEG'S ACTUAL LIAP EXPENDITURE IN FY 2004?

A. The Company's response to Division Data Request No. 2-03 indicates that $1,615,310 were disbursed for Low Income Heating Assistance Program (LIHEAP) activities and $200,000 were disbursed for Low Income Weatherization. Thus, a total of $1,815,310 (or 101.2% of annual funding through base rates) was disbursed during FY 2004.

Q. DOES NEG SEEK ADDITIONAL LIAP FUNDING THROUGH ITS PROPOSED DSM FACTOR IN THIS PROCEEDING?

A. No, it does not. NEG entered FY 2004 with a LIAP balance carry-forward of $33,635. Despite expenditures in excess of annual funding level during FY 2004, the Company has a carry-forward balance of LIAP funds for FY 2005 of $3,325. Therefore, the LIAP factor remains at zero.

Q. DO YOU FIND ANY REASON TO QUESTION THE APPROPRIATENESS OF EITHER THE COMPANY'S FUNDING OF LIAP PROGRAMS OR THE LEVEL OF THE LIAP FACTOR IT PROPOSES IN THIS PROCEEDING?

A. With one minor exception, NEG's LIAP factor costs and computation appear to be appropriate. The exception is NEG apparent omission of the $33,635 FY 2003 carry over balance from its LIAP factor computations. The dollar impact of this omission is small (i.e., $33,635 at 2.1% interest for 12 months = $713) and has no significant impact on the LIAP factor. But, for accuracy and consistency the Company should include any carry forward balance in all future LIAP calculations.

<u>Environment Response Cost Factor</u>

Q. PLEASE DESCRIBE THE PURPOSE OF THE ENVIRONMENTAL RESPONSE COST (ERC) FACTOR?

A. The primary function of the ERC factor is to provide the Company a means of recovering "reasonable and prudently incurred" environmental response costs while limiting impacts on customers' bills. Costs subject to recovery through the ERC Factor include:

(1) Costs for evaluation, remediation and clean-up of sites associated with NEG's ownership and operation of manufactured gas plants, manufactured gas storage facilities, and manufactured gas plant-related off-site waste disposal locations;

(2) Costs for removal and disposal of mercury regulators and meters; and

(3) Costs for acquiring property associated with the clean up of such sites;

(4) Litigation costs, claims, judgments, and settlements associated with environmental clean up activities.

Q. HOW ARE REASONABLE AND PRUDENTLY INCURRED ENVIRONMENTAL RESPONSE COSTS RECOVERED THROUGH THE ERC FACTOR?

A. According to the terms of the settlement approved by this Commission in Docket No. 3401, such Environmental Response Costs shall be recovered through a 10-year straight-line amortization, subject to the restriction that the ERC factor shall be limited to an increase of no more than $0.01 per therm in any annual DAC filing. Moreover, the ERC factor is computed to reflect an adjustment to the $1,310,000 of Environmental Response Costs that is presently included in NEG's base rate charges. Thus, the dollar amount subject to recovery through the ERC factor in any year reflects the sum of all applicable 10-year ERC amortizations less the $1,310,000 of budgeted base rate recoveries, and the ERC factor reflects that net dollar amount divided by forecasted firm throughput.

Q. WHAT IS THE NET DOLLAR AMOUNT THAT NEG PROPOSES IN THIS PROCEEDING FOR RECOVERY THROUGH ITS ERC FACTOR?

A. As shown in Revised Attachment PCC-4, filed on September 3, 2004, the Company seeks approval of a net recovery of ($641,514). That net dollar amount reflects:

1. A 10-year amortization of $12,510,252 of net ERC costs incurred through the end of FY 2002;

2. A 10-year amortization of ($6,012,673) of net ERC costs for net FY 2003;

3. A 10-year amortization of ($187,282) of net ERC costs for net FY 2004; and

4. A deduction of $1,310,000 for budgeted base rate recovery of ERC costs during the annual period in which the proposed ERC Factor will be effective.

Q. HOW DID NEG ARRIVE AT A NEGATIVE ERC COST RECOVERY REQUIREMENT FOR FY 2004?

A. The $187,282 that the Company includes in is ERC Factor computations for FY 2004 represents the net of $831,038 of reported actual FY 2004 Environmental Projects costs less a $643,756 of additional proceeds from insurance settlements.

Q. WHAT IS THE AMOUNT OF THE ERC FACTOR THAT NEG PROPOSES IN THIS PROCEEDING?

A. NEG proposes an ERC factor of ($0.0018) per therm. That represents a net credit to firm customers.

Q. IS THE ERC FACTOR THAT THE COMPANY PROPOSES REASONABLE AND APPROPRIATE?

A. No. The vast majority of the Company's reported net activity for FY 2004 (i.e., $661,086 of a total of $831,038) is shown on page 2 of Attachment PCC-4 of Mr. Czekanski's July 30, 2004 filing to be costs for "**General Enviro Issues**." Through discovery (i.e., the Company's response to Division Data Request No. 1-07 and subsequent discussions with NEG personnel, it appears that $660,242 of the identified costs for "General Enviro Issues" for FY 2004 reflects an offset for the negative net credit provided to firm customers through the ERC factor during FY 2004. That $660,242 amount appears to be inappropriate for inclusion in the Company's ERC factor. It is neither a newly incurred environmental cost nor a cost for which NEG requires further compensation. Thus, I recommend that the Company's ERC factor be recomputed with that $660,242 amount excluded.

When the $660,242 is excluded from NEG's FY 2004 Environmental Response costs, the reported activity for FY 2004 falls to $170,796. Furthermore, when the $643,756 of additional insurance proceeds in FY 2004 is subtracted, the revised Net Environmental Cost for FY 2004 becomes ($472,960). Substituting the revised FY 2004 Net Environmental Cost of ($472,960) in the ERC Factor Formula for the previously computed $187,282 amount yields net recovery amount for FY 2005 of ($707,538) and a ERC Factor of ($0.0199) per Dth, or ($0.0020) per therm. (See Schedule BRO-2 attached to this testimony).

Q. DO YOU HAVE ANY FURTHER CONCERNS REGARDING NEG'S ERC FACTOR COMPUTATIONS IN THIS PROCEEDING?

A. Yes. I have two.

First, to date NEG has not provided sufficient information to support a determination regarding the reasonableness and prudence of the insurance settlement amounts that the Company has credited against the Environmental Response Costs it has incurred. Therefore, the Division continues to refrain from offering a final determination regarding the reasonableness or appropriateness of the insurance settlement amounts that NEG has reflected in either its current DAC filing or in the DAC filing it submitted last year.

Second, through discovery in this proceeding the Division has learned for the first time of an accounting entry that NEG suggests was made some time prior to NEG's last DAC filing which transfers and consolidates $263,263 of Mercury regulator related environmental expenditures from the former Valley Gas Company into NEG's Account 171 costs.[3] However, the Division also observes that the Company's FERC Form No. 2 for the year ended June 30, 2004 at page 20, line 97, column (f), reflects a transfer of an identical amount of costs (i.e., $263,263 from the Company's FERC Account for House Regulators (FERC Acct. No. 383) during that 12-month period. Thus, there appears to be some question regarding when those costs were actually recorded by NEG as Environmental Response costs. Also, due to differences in the regulatory treatments of such expenditures for Valley Gas Company and Providence Gas Company prior to the consolidation of those companies, the Division submits that NEG should be required to demonstrate that it is reasonable or appropriate to conclude that the identified costs for the mercury regulator related environmental response costs for the former Valley Gas Company were NOT previously recovered through Valley Gas Company rates.

Q. DO YOU HAVE ANY FURTHER RECOMMENDATIONS REGARDING THE COMPANY'S ENVIRONMENTAL RESPONSE COSTS?

A. Yes. The Division's experience in the review of the Company's DAC filings suggests that the current schedule for investigation of Environmental Response costs

[3] See NEG's response to Division Data Request DIV 1-07c, submitted on September 13, 2004.

could be facilitated by earlier provision of greater detail and specificity regarding the nature of elements of the Company's cost claims and its justifications for the incurrence of those costs. Often multiple rounds of discovery are required to begin to gain an understanding of the Company's claimed environmental costs and insurance proceeds and the projects or activities to which they relate. In this context, the Division suggests that the Commission adopt requirements for the Company to:

(1) File a mid-year environmental report regarding the nature of, and reasons for, environmental costs actually incurred and amounts received as credits against its recorded environmental costs during the first half of each fiscal year, as well as projects of its anticipated environmental expenditures and receipts for the second half of the fiscal year; and

(2) Submit with its annual DAC filing information relating to environmental expenditures in the second half of the fiscal year just completed with detail comparable to that required in the mid-year environmental report, as well as (a) documentation and explanations of updates or revisions to previously reported data for the first half of the fiscal year

and (b) a detailed forecast of anticipated environmental expenditures and receipts for the first half of the next fiscal year.

<u>On-System Margin Credits</u>

Q. WHAT IS THE ROLE OF THE ON-SYSTEM MARGIN CREDIT (MC) FACTOR?

A. The On-System Margin Credit (MC) Factor performs two functions. First, it provides NEG a mechanism for recovery of shortfalls, if any, in the actual on-system margin revenue derived from non-firm sales and transportation services relative to the $1.6 million of annual on-system margin revenue presently assumed in the design of the Company's base rates. Second, the MC Factor provides a mechanism for sharing of on-system margin revenue in excess of the level assumed in the design of base rates. If actual non-firm margin revenue exceeds $1.6 million within the 12-month period ending June 30th of any year completed subsequent to the effective date of this tariff provision, the MC Factor provides an incentive to the Company to maximize such margin revenue by enabling NEG to retain 25% of such revenue while crediting 75% of on-system non-firm margins to firm service customers as an offset to their distribution system costs.

Q. DID NEG ACHIEVE ON-SYSTEM NON-FIRM MARGINS IN EXCESS OF $1.6 MILLION FOR THE 12-MONTH PERIOD ENDED JUNE 30, 2004?

A. Yes. Mr. Czekanski's July 30, 2004 testimony in this docket indicates that NEG recorded non-firm margin revenue for the 12-months ended June 30, 2003 of $1,928,686. Thus, $328,686 of non-firm margin revenue was collected during FY 2004 in excess of the $1.6 million annual level (presently assumed in the design of NEG's base rates). As explained above, 75% of that amount ($246,514) is subject to distribution as a credit to firm customers through the MC factor in the Company's DAC calculations. NEG retains 25% or $82,172. The resulting On-System Margin Credit (MC Factor) per therm is $0.0007.

Q. ARE NEG'S CALCULATIONS OF SHARED MARGINS AND THE MC FACTOR FOR THE 12 MONTHS ENDED JUNE 30, 2004 REASONABLE AND APPROPRIATE?

A. The mathematical computations detailed in Attachment PCC-5 are correct. Thus, assuming the total dollar amount of margin revenue that NEG reports is accurate, the calculated MC Factor should be accepted. However, the Division's efforts to verify NEG's reported non-firm margin revenue has encountered mixed results.

In response to Division Data Request No. 1-09, NEG has provided data regarding the margin revenue it derived from non-firm customers during the 12-

months ended June 30, 2004 by month, disaggregated by alternate fuel type and showing data separately for non-firm sales service, delivery service and TSS customers. Although the information contained in that response appears to verify the total amount of non-firm margin revenue computed in Attachment PCC-5, the monthly distribution of the reported margin revenue is quite different. Schedule BRO-3 offers a comparison of the non-firm revenue by month from Mr. Czekanski's Attachment PCC-5 and what is understood to be comparable data provided in Attachment DIV 1-9. Informal follow-up conversations with NEG personnel indicate that the observed differences in non-firm margin revenue by month are attributable to the timing of billing adjustments, which in aggregate were quite substantial during portions of FY 2004.

At this point, further verification of the Company's reported margin revenue is not possible without delving into cost and revenue detail on a month-by-month, customer-by-customer basis. From the Division's perspective, the expected benefits to ratepayers of that effort are not likely to justify the added costs that the Division and NEG would need to incur. Therefore, I recommend that the Commission accept NEG witness Czekanski's explanation of those differences for FY 2004. I also recommend that the Commission require NEG to develop and have available for Division inspection, at the time of each subsequent annual DAC filing, monthly billing detail for each of its non-firm customers on a customer-by-customer basis for the Company's most recently completed fiscal year.

Weather Normalization

Q. WHAT IS THE INTENDED ROLE OF THE COMPANY'S WEATHER NORMALIZATION FACTOR?

A. The Weather Normalization Factor provides a mechanism for moderating the impacts of weather on the Company's revenue. When winter weather, as measured in Heating Degree Days (HDDs), is warmer than normal, NEG's collection of fixed costs through its charges for distribution service declines below the level anticipated under normal weather conditions. If the resulting decline in heating degree days is significant, a positive Weather Normalization Factor is computed for the subsequent DAC period to compensate the Company for a portion of the revenue not realized due to reduced system throughput. On the other hand, colder than normal winter weather causes system throughput and distribution charge revenue to increase relative to expected revenue levels under normal weather conditions. If recorded HDDs are greater than anticipated normal degree day levels, a negative Weather Normalization Factor (credit) returns a measure of excess revenue collections to customers during the subsequent DAC period.

However, the Weather Normalization Factor only addresses heating degree days recorded for each year that are more than 2% above or below forecasted normal heating degree day levels when accumulated over the defined winter season (i.e., the months of November through April). If recorded actual HDDs are within plus or minus 2% of normal levels for the winter season, the Weather Normalization Factor for the subsequent DAC is zero. Where total HDDs for the winter season are more than 2% above normal heating degree day expectations, each heating degree day below the normal expectation less 2%, or above normal expectations plus 2%, is multiplied by $9,000 per degree day to obtain the total dollar amount to be recovered from, or credited to, customers through the Weather Normalization Factor.

Q. WAS THE 2003-2004 WINTER SEASON EITHER WARMER OR COLDER THAN NORMAL BY A SUFFICIENTLY LARGE NUMBER OF HEATING DEGREE DAYS TO TRIGGER THE COMPUTATION OF A NON-ZERO WEATHER NORMALIZATION FACTOR FOR NEG?

A. Yes. Attachment PCC-6 filed with witness Czekanski's July 30, 2004 testimony in this docket indicates that actual weather for the months of November 2003 through April 2004 comprised 4,961 degree days. In past proceedings, NEG has represented that under normal weather conditions the Company would expect 4,778 heating degree days for the six month period in a typical winter. But, given that 2004 is a leap year, NEG adjusts its normal heating degree day total to reflect one additional winter day in February. Thus, NEG uses 102% of a leap-year adjusted normal heating degree day measure to derive an adjusted upper bound for the plus or minus 2% dead band around normal heating degree day expectations. As a result, the upper bound that the Company uses for the plus or minus 2% dead band is 4,903 HDD. Using that leap-year adjusted upper bound, NEG computes that the winter of 2003-2004 contained **58** HDDs in excess of normal expectations plus 2%.

Q. GIVEN THE COMPANY'S RECORDED ACTUAL HEATING DEGREE DAYS FOR THE MONTHS OF NOVEMBER 2003 THROUGH APRIL 2004, IS A NON-ZERO WEATHER NORMALIZATION FACTOR NECESSARY AND APPROPRIATE?

A. Yes. The 58 HDDs above normal levels plus 2% multiplied by $9,000 per excess HDD generates a Weather Mitigation Credit for firm customers of $522,000 and a Weather Normalization (WN) Factor of ($0.0015) per therm. I find no substantial reason to question the mathematical accuracy of these NEG computations as presented in Attachment PCC-6 to Mr. Czekanski's July 30, 2004 testimony or its conformance with the Company's current tariff provisions.[4]

4 I must note, however, that the current methodology for computing these weather-normalization adjustments assumes that gas usage varies in a linear relationship with changes in Heating Degree Days. Yet, within the last year, NEG personnel have suggested that the relationship between HDDs

Reconciliation Factor

Q. HOW IS THE RECONCILIATION (R) FACTOR COMPUTED?

A. The Reconciliation (R) Factor component of the Company's DAC adjusts for differences between revenue collections associated with each component of DAC and either actual costs or budgeted revenue by component, adjusted for interest on deferred balances. In this proceeding, the R factor computations only include reconciling adjustments for System Pressure, Demand Side Management, Low Income Assistance, and Environmental Response Costs. In future proceedings, reconciling adjustments for a greater number of components in NEG's DAC computations may be required.

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and gas use for NEG's firm service customers is no longer linear during periods of extreme weather and that NEG has revised it's planning to reflect the non-linear nature of the relationship between HDDs and firm gas use under extreme weather conditions. More specifically, Mr. Beland suggests that differences between average use per degree day and marginal use per degree day have grown considerably, increasing the need for peaking supply. If Mr. Beland is correct, the underlying presumptions of the current WN Factor (i.e., that the revenue impact of degree day variations is relatively uniform in terms of dollars per heating degree day for all heating degree day variations) may need to be adjusted. For these reasons, I encourage the Commission to investigate the need for revising the weather adjustment methodology that NEG uses to compute the WN Factor within the DAC such that revenue adjustments more closely track the actual impacts of weather on customers' usage and the Company's billings.

Q. ARE THE RECONCILING ADJUSTMENTS THAT NEG HAS COMPUTED AS PART OF THE "R" FACTOR COMPONENT OF ITS DAC REASONABLE AND APPROPRIATE?

A. With one minor exception, the Company's reconciliation adjustments appear to be reasonable and appropriate. As noted in NEG's response to Division Data Request No. 1-12, the Company inadvertently omitted interest from the reconciliation adjustment calculations for the On-System Credits and Weather Normalization for forecasted months reflected in PCC-7 attached to Mr. Czekanski's July 30, 2004 testimony and the Revised PCC-7 submitted with Mr. Czekanski's September 3, 2004 testimony. Assuming that actual data for the months of July through October 2004 do not vary dramatically from the forecasted levels incorporated in the referenced Attachments, the impact of the referenced omission is small[5] and, due to rounding, will most likely have no impact on the proposed R factor.

Distribution Adjustment Charge (DAC) Summary

Q. WHAT ARE THE DISTRIBUTION ADJUSTMENT CHARGES THAT NEG PROPOSES IN THIS PROCEEDING?

[5] NEG estimates in its response to Division Data Request DIV 1-12 that the inadvertently omitted interest on forecasted monthly balances for the months of July through October 2004 would amount to $2,838.

A. The Company's proposed DAC charge is presented in Revised Attachment PCC-1 filed on September 3, 2004. That charge is $0.0021 per therm for all customers, including the adjustment for uncollectible accounts. If NEG's proposals are approved as presented in Revised Attachment PCC-1, that new **charge** would replace the current DAC which is ($0.0248) per therm and reflects a **credit** to NEG's firm gas service customers.

Q. HOW DO YOUR PROPOSED ADJUSTMENTS IMPACT THE COMPANY PROPOSED DAC?

A. When the adjusted ERC factor computed herein is rolled into NEG's overall DAC determinations, the new DAC charge would be $0.0018 per therm, after rounding and including the adjustment for uncollectibles. That charge would be applicable uniformly to the throughput for all firm service customers.

<u>Other Considerations</u>

Q. HAS NEG PROPERLY COMPUTED THE BILL IMPACTS THAT WOULD RESULTS FROM ITS PROPOSED DAC CHARGE?

A. For most classes of customers it has. However, an error was identified in the bill impact computations presented for Residential Non-Heating customers in both

Attachment PCC-2 and Revised Attachment PCC-2 which significantly distorts the results of that customer class. As verified in NEG's response to Division Data Request DIV 1-06, the referenced attachments inadvertently reflected a current DAC of ($0.2480) in place of the actual current DAC which is ($0.0248). Corrected Attachment PCC-2, dated September 13, 2004, which was attached to NEG Response to Division Data Request DIV 1-06, more accurately indicates the impacts of the Company's proposed DAC on Residential Non-Heating customers. As indicated therein, NEG's proposed DAC would increase most Residential Non-Heating customers' annual bills by $3 to $5 per year, or 1.3% to 1.5%.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

New England Gas Company
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LNG Commodity Related Costs

LNG Withdrawal Commodity Costs	2003-04	2004-05	Increase (Decrease) $	Increase (Decrease) %
November	$ 144,917	$ 190,256	$ 45,339	31.3%
December	$ 181,071	$ 197,996	$ 16,925	9.3%
January	$ 2,424,740	$ 4,133,946	$ 1,709,206	70.5%
February	$ 628,870	$ 157,016	$ (471,854)	-75.0%
March	$ 179,013	$ 166,440	$ (12,573)	-7.0%
April	$ 138,869	$ 159,969	$ 21,100	15.2%
May	$ 141,693	$ 163,147	$ 21,454	15.1%
June	$ 135,468	$ 155,889	$ 20,421	15.1%
July	$ 138,596	$ 159,104	$ 20,508	14.8%
August	$ 137,356	$ 157,445	$ 20,089	14.6%
September	$ 131,886	$ 150,993	$ 19,107	14.5%
October	$ 135,265	$ 155,029	$ 19,764	14.6%
Total	$ 4,517,744	$ 5,947,230	**$ 1,429,486**	**31.6%**
LNG Inventory Costs	$ 568,450	$ 565,149	$ (3,301)	**-0.6%**
LNG Demand Costs	$ 3,405,240	$ 3,320,600	$ (84,640)	**-2.5%**
TOTAL LNG COSTS	$ 8,491,434	$ 9,832,979	$ 1,341,545	15.8%
LNG Withdrawal Volume	544,804	756,091	211,287	**38.8%**
Avg Withdrawal Cost ($/Dth)	**$ 8.29**	**$ 7.87**	**$ (0.43)**	**-5.1%**

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Revised Calculation for NEG Evironmental Response Cost (ERC) Factor

Ln No			$
1	Total FY 2004 Evironmental Response Cost Activity	$	831,038
2	Less Excluded "General Enviro Issues" Costs	$	(660,242)
3	Adjusted FY 2004 Evironmental Response Cost Activity (Line 1 + Line 2)	**$**	**170,796**
4	Less FY 2004 Insurance Proceeds	$	(643,756)
5	Adjusted Net FY 2004 Environmental Costs (Line 3 + Line 4)	$	(472,960)
6	Adjusted 10-Year Amortization of FY 2004 Environmental Costs (Line 5 / 10)	$	(47,296)
7	FY 2004 Net Evironmental Costs as Computed by NEG	$	187,282
8	10-Yr Amortization of NEG's Computed FY 2004 Net Environmental Costs (Line 7 / 10)	$	18,728
9	Total ERC Factor Costs as Computed by NEG	$	(641,514)
10	Adjusted Total ERC Factor Costs (Line 9 - Line 8 + Line 6)	**$**	**(707,538)**
12	Nov 2004 - Oct 2005 Firm Throughput (Dth)		35,569,425
13	ERC Factor ($/Dth)	$	(0.0199)
14	ERC Factor ($/Therm) (Line 13 / 10)	**$**	**(0.0020)**

New England Gas Company
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Comparison of Monthly On-System Revenue Margins by Month for FY 2003

Month/Year		Attachment PCC-5 Filed 30-Jul-04	Attachment DIV 1-9 Provided 29-Sep-04	Difference $	Difference %
July	2003	$ 68,501	$ 115,442	$ 46,941	68.53%
August	2003	$ 98,923	$ 100,444	$ 1,521	1.54%
September	2003	$ 107,199	$ 114,296	$ 7,097	6.62%
October	2003	$ 97,550	$ 126,212	$ 28,662	29.38%
November	2003	$ 279,935	$ 281,189	$ 1,254	0.45%
December	2003	$ 83,113	$ 217,988	$ 134,875	162.28%
January	2004	$ 27,249	$ 156,644	$ 129,395	474.86%
February	2004	$ 100,430	$ 133,777	$ 33,347	33.20%
March	2004	$ 547,144	$ 225,587	$ (321,557)	-58.77%
April	2004	$ 264,703	$ 203,239	$ (61,464)	-23.22%
May	2004	$ 124,117	$ 132,779	$ 8,662	6.98%
June	2004	$ 129,822	$ 121,090	$ (8,732)	-6.73%
Total		$ 1,928,686	$ 1,928,687	$ 1	0.00%