
Data Request WILEY 1-1

Request:

Please describe any low income gas discount programs or policies that National Grid (NG) and/or KeySpan uses in any other state, including inter alia:

a. Where the program or policy applies;

b. To whom it applies (eligibility criteria);

c. The amount of the discount;

d. The charges to which the discount applies;

e. The approximate monthly dollar value of the discount for the average low-income consumer;

f. Whether the discount is required by law, and, if so, the citation to the applicable law;

g. The dates each such program or policy has been in effect;

h. Whether the cost of the discount is passed on to other customers, and, if not, the source of the funding for the program or policy;

i. The annual cost of each such program or policy for the last three years, listing the cost of the discount and the cost of program administration separately.

Response:

The Brooklyn Union Gas Company, d/b/a National Grid.

Low Income Discount Rates:

a. In New York, a low-income discount program applies in the service territory of The Brooklyn Union Gas Company, d/b/a National Grid.

b. The low income discount is available to all residential non-heating and heating customers of record who are recipients of: Aid to Families with Dependent Children, Home Relief, Supplemental Security Income, Medicaid, Food Stamps,

Response: WILEY 1-1 (continued)

Home Energy Assistance Program, Veteran's Disability Pension, Veteran's Surviving Spouse Pension or Child Health Plus. The total number of low-income customers is projected not to exceed 60,000.

c. d. e. For low-income residential non-heating customers, the average monthly discount of $2.50 is applied to the minimum charge. The low-income residential heating discount has two components and is seasonal. The average monthly discount of $9.50 is applied to the minimum charge. The average monthly second block discount of $12.44 for the typical low-income residential heating customer, is applied only during the winter period (from November to April.)

f. The discount programs are set forth in The Brooklyn Union Gas Company tariffs and are not required by law.

g. The Low Income Discount Program has been in place since October 1994.

h. The cost of the low-income discounts are included in the delivery rates of all firm customers.

i. The total annual cost for the low income discount, effective January 1st, 2008, is $7.35 million. For three years prior to 2008, the total annual discount was $1.3 million.

The cost of program administration is not tracked.

Neighborhood Heating Fund - NY

This program, which was first created by National Grid in 1983, provides financial assistance to low-income heating customers and is administered by Heart Share Human Services of New York. Eligibility is based on New York State Home Energy Assistance (HEAP) income guidelines and funds are available on a first come, first served basis. Customers can receive a grant up to $200. National Grid makes a yearly contribution to the program of $150,000 and pays $30,000 for administrative costs. These costs are not passed on to other customers. Historically the program starts the second week of December and runs until funds are depleted. Consumer Advocacy has designated one customer service representative who works with Heart Share to administer the program.

Response: WILEY 1-1 (continued)

KeySpan Gas East Corp. d/b/a Brooklyn Union of L.I. d/b/a National Grid.

Low Income Discount Rates:

a. The low-income discount program applies to the service territory of KeySpan Gas East Corp. d/b/a Brooklyn Union of L.I. d/b/a National Grid.

b. The low-income discount is available to all residential non-heating and heating customers of record who are recipients of: Aid to Families with Dependent Children, Home Relief, Supplemental Security Income, Medicaid, Food Stamps, Home Energy Assistance Program, Veteran's Disability Pension, Veteran's Surviving Spouse Pension or Child Health Plus. The total number of low-income customers is projected not to exceed 30,000.

c. d. e. For low-income residential non-heating customers, the average monthly discount of $2.50 is applied to the minimum charge year-round. The low income residential heating discount has two components and is seasonal. The average monthly discount of $9.50 is applied to the minimum charge year-round. The average monthly second block discount of $17.03, for the typical low income residential heating customer, is applied to only during the winter period (from November to April.)

f. The discount programs are set forth in the Brooklyn Union of L.I. tariffs and are not required by law.

g. The Long Island Low Income Discount Program became effective January 1st, 2008.

h. The cost of the low-income discounts are included in the delivery rates of all firm customers.

i. The total annual cost of the low income discount is $4.77 million.

The cost of program administration is not tracked.

Project Warmth – LI

This is a community-based partnership between National Grid and the United Way of Long Island, which began in 1995. The partnership works to help Long Island families suffering from recent financial hardships meet their heating needs, regardless of fuel type. The program provides a one-time grant of up to $200 for

Response: WILEY 1-1 (continued)

fuel, plus $100 for fuel-related electricity during the heating assistance program period of October 1 through September 30 of the following year, as long as funds are available. During the cooling assistance program period of June 1 through September 30, special needs customers may apply for a one-time grant of up to $300 for electricity. The program is funded by a grant from the National Grid Foundation. Consumer Advocacy has designated one customer service representative who works with the United Way of Long Island to administer the program. The annual contribution to the program varies annually. In the past year, National Grid has contributed $120,000. This cost is not passed on to other customers.

Niagara Mohawk Power Corporation d/b/a National Grid.

Niagara Mohawk currently does not have a low-income discount program.

AffordAbility

Customers enrolled in the Company's AffordAbility program are referred to the New York State Energy Research and Development Authority (NYSERDA) EmPower NY program for delivery and installation of energy saving measures in the home. All participants receive an energy education packet including educational brochures and energy efficient light bulbs. In addition, the customer may participate in financial and energy education workshops. Customers receiving weatherization are provided a 25% discount, customers receiving significant appliance replacement are provided a 30% discount, and customers receiving both services are provided a 35% discount.

EmPower New York Niagara Mohawk Gas Customer Efficiency Program

The Program is funded through a $5 million allocation under an agreement with the New York State Energy Research and Development Authority (NYSERDA) to expand the delivery of natural gas efficiency services to low-income natural gas customers.

The program offers expanded energy efficiency services for low income gas customers, including cost-effective natural gas usage reduction measures. Natural gas customers with household income below 60% of state median (i.e., HEAP-eligible) are eligible.

Response: WILEY 1-1 (continued)

Boston Gas Company, Essex Gas Company, and Colonial Gas Company, d/b/a National Grid.

Low Income Discount Rates:

a. Low-income discount rates apply in the service territories of Boston Gas Company, Essex Gas Company, and Colonial Gas Company, d/b/a National Grid.

b. The low-income discount is available to residential heating and non heating customers who are recipients of: fuel assistance, supplemental security income, families with dependent children, general relief, refugee resettlement, food stamps, Medicaid and veterans benefits, who are 18 years of age or older, head of household, and Boston Gas/Essex Gas/Colonial Gas customer of record.

c. Approximate percent of discount for each of the MA companies:
   Boston Gas: 40% (distribution rate only)
   Essex Gas: 36% (distribution rate only)
   Colonial Gas – Lowell: 38% (distribution rate only)
   Colonial Gas – Cape: 37% (distribution rate only)

d. The discount applies to all delivery rates of Residential Heating and Non-Heating customers.

e. The approximate monthly dollar value of the discount for each of the MA companies:

	Boston	Essex	Lowell	Cape
10/1/04 – 9/30/05	$13.02	$14.39	$13.38	$12.92
10/1/05 - 9/30/06	$9.96	$9.76	$9.19	$9.28
10/1/06 – 9/30/07	$10.67	$9.83	$9.34	$9.87

f. The discount programs are set forth in the Boston Gas, Essex Gas and Colonial Gas tariffs and are not required by law.

g. The Low Income Discount Program has been in place since early 1990's.

h. The low income discount costs are recovered as a volumetric surcharge from all Firm Sales and Transportation Customers through the Local Delivery Adjustment Clause.

Prepared by or under the supervision of: Peter Czekanski

Response: WILEY 1-1 (continued)

i. The annual cost of the discount for each of the MA companies:

	Boston	Essex	Lowell	Cape
10/1/04 – 9/30/05	$4,195,220	$350,814	$615,577	$425,124
10/1/05 -9/30/06	$4,638,629	$381,653	$647,580	$411,041
10/1/06 – 9/30/07	$5,228,381	$406,536	$696,996	$445,858

The cost of program administration is not tracked.

Energy North Natural Gas Inc., d/b/a National Grid.

Low Income Discount Rates:

a. The low-income discount program applies in the service territory of Energy North Natural Gas Inc., d/b/a National Grid.

b. The low-income discount is provided to residential heating customers who qualify for a benefit through a list of qualified programs.

c. The Energy North residential heating monthly delivery charges for the low income program are currently discounted 60% of the Residential Heating Rate Class R-3.

d. The discount is applied to all delivery rates for eligible customers.

e. Energy North's current average monthly discount was approximately $13 per month for the 2005-2006 period, approximately $16 for the 2006-2007 period and is currently approximately $19 per month for 2007-2008 period.

f. The Energy North Residential Low Income Discount Pilot Program was approved by the NHPUC in Docket No. DG 05-076, September 1, 2005 in Order No. 24,508. The Low Income Discount Program was continued in Docket No. DG 06-120 and approved by the NHPUC on September 22, 2006 in Order No. 25,669.

g. The Energy North low-income discount program became effective November 1, 2005.

h. The Energy North Low Income Discount and costs are recovered as a volumetric surcharge from all Firm Sales and Transportation Customers through the Local Delivery Adjustment Clause.

Prepared by or under the supervision of: Peter Czekanski

Response: WILEY 1-1 (continued)

i. See the summary below of Energy North's Residential Low Income Discount Program costs

	2005-06	2006-07	2007-08 *
Discount Costs	$708,688	$861,908	$1,169,214
Admin Costs	42,839	10,078	8,650
Total	$751,527	$871,986	$1,177,864

* The 2007-08 period includes projected costs for June – October 2008.

Data Request WILEY 1-2

Request:

For each jurisdiction identified in the answer to request 1-01, please describe:

a. The policies in effect in that jurisdiction concerning management of arrearages;

b. The range of payment plans available in that jurisdiction, including whether the jurisdiction permits payment plans designed to be consistent with a customer's ability to pay;

c. The percentage down payment on arrearages required after termination, including whether those percentages change if the customer is terminated more than once.

Response:

The Brooklyn Union Gas Company, d/b/a National Grid.

a. The arrearage management policies state that the customer must pay the full amount of arrears and a down payment (no specific percentage).

b. Only the agreements for low income customers are based on their arrearage balances and ability to pay at the discretion of the representative (the representative could go as low as a $10 agreement if needed). The amounts are determined based on the customer's financial situation and supporting documentation.

c. The customer must pay the 100% of arrearages balances after termination. This does not change if the customer is terminated more than once.

Payment Plan - Deferred Payment Agreements (DPA)

The Company offers any eligible residential customer a deferred payment agreement (DPA). All residential customers are eligible for a DPA unless the customer has defaulted on an existing DPA, which required payment over a period of at least as long as the standard agreement or the Commission determines that the customer has the resources to pay the bill. A customer will become ineligible for a DPA if he has defaulted on an existing DPA.

Response: WILEY 1-2 (continued)

If the Company and the customer or applicant are unable to agree upon specific terms, the Company will offer a DPA with the following terms: (a) a down-payment up to 15 percent of the amount covered by the payment agreement or the cost of one-half of one month's average usage, whichever is greater, or if the amount covered by the agreement is less than one-half of one month's average usage, 50 percent of such amount; (b) and monthly installments up to the cost of one-half of one month's average use or one-tenth of the balance, whichever is greater.

The Company also offers DPAs to non-residential customers. A non-residential customer will not be eligible if: he owes any amount under a prior deferred payment agreement; or has failed to make timely payments under a deferred payment agreement in effect during the previous twelve (12) months; or is a publicly held company, or a subsidiary thereof; or a seasonal, short-term or temporary customer; or who the Company can demonstrate has the resources to pay the bill, provided that the Company notifies the non-residential customer of its reasons and of the customer's right to contest this determination through the Commission's complaint procedures; or who during the previous twelve (12) months had a combined total consumption for all its accounts with the Company in excess of 4,000 therms.

Payment Plan - On Track

On Track is an 18-month program for low income customers, which began in 1993. The program is designed to educate consumers on efficient energy use and to encourage timely, regular bill payment through behavior modification techniques that include financial and energy management education, consistent customer representative support, and social service referrals. Customers must meet specific program criteria to be eligible. The criteria are as follows: Household gross income must be under 250% of the Federal Poverty Level (FPL). This includes customers that have received or will receive a HEAP grant during the enrollment year. The account must be for heating in a one or two family home. The account holder must be primarily responsible for payment of the gas bill. The customer may not receive any other public assistance (outside of HEAP) that covers their gas costs. The customer must be determined financially capable of making at least the minimum deferred payment agreement in addition to their current bills via enrollment in balanced billing.

Arrears Forgiveness is provided if the terms of the DPA (Deferred Payment Agreement) are kept; customers will be granted allowances up to a maximum amount of $400. The allowances are applied four times over the course of the

Response: WILEY 1-2 (continued)

program in the amount of $100 each. The maximum annual estimated cost of this program is of $960,000. This cost is not passed on to other customers.

Projected enrollment is 2400 customers. Currently National Grid has 632 enrolled customers.

Payment Plan - Budget Billing

The Company offers a Budget Billing Plan.

KeySpan Gas East Corp. d/b/a Brooklyn Union of L.I. d/b/a National Grid.

a. The arrearage management policies state that the customer must pay the full amount of arrears and a down payment (no specific percentage).

b. Only the agreements for low-income customers are based on their arrearage balances and ability to pay at the discretion of the representative (the representative could go as low as a $10 agreement if needed). The amounts are determined based on the customer's financial situation and supporting documentation.

c. The customer must pay the 100% of arrearages balances after termination. This does not change if the customer is terminated more than once.

Payment Plan -Deferred Payment Agreements (DPA)

The Company offers any eligible residential customer a deferred payment agreement (DPA.) All residential customers are eligible for a DPA unless the customer has defaulted on an existing DPA, which required payment over a period of at least as long as the standard agreement or the Commission determines that the customer has the resources to pay the bill. A customer will become ineligible for a DPA if he has defaulted on an existing DPA.

If the Company and the customer or applicant are unable to agree upon specific terms, the Company will offer a DPA with the following terms: (a) a down-payment up to 15 percent of the amount covered by the payment agreement or the cost of one-half of one month's average usage, whichever is greater, or if the amount covered by the agreement is less than one-half of one month's average usage, 50 percent of such amount; (b) and monthly installments up to the cost of one-half of one month's average use or one-tenth of the balance, whichever is greater.

Response: WILEY 1-2 (continued)

The Company also offers DPAs to non-residential customers. A non-residential customer will not be eligible if: he owes any amount under a prior deferred payment agreement; or has failed to make timely payments under a deferred payment agreement in effect during the previous twelve (12) months; or is a publicly held company, or a subsidiary thereof; or a seasonal, short-term or temporary customer; or who the Company can demonstrate has the resources to pay the bill, provided that the Company notifies the non-residential customer of its reasons and of the customer's right to contest this determination through the Commission's complaint procedures; or who during the previous twelve (12) months had a combined total consumption for all its accounts with the Company in excess of 4,000 therms.

Payment Plan - On Track

On Track is an 18-month program for low-income customers, which began in 1998. The program is designed to educate consumers on efficient energy use and to encourage timely, regular bill payment through behavior modification techniques that include financial and energy management education, consistent customer representative support, and social service referrals. Customers must meet specific program criteria to be eligible. The criteria are as follows: Household gross income must be under 250% of the Federal Poverty Level (FPL), which includes customers that have received or will receive a HEAP grant during the enrollment year. The account must be for heating in a one or two family home. The account holder must be primarily responsible for payment of the gas bill. The customer may not receive any other public assistance (outside of HEAP) that covers their gas costs. The customer must be determined financially capable of making at least the minimum deferred payment agreement in addition to their current bills via enrollment in balanced billing.

Arrears Forgiveness is provided if the terms of the DPA (Deferred Payment Agreement) are kept; customers will be granted allowances up to a maximum amount of $400. The allowances are applied four times over the course of the program in the amount of $100 each. The maximum annual estimated cost of this program is of $160,000. This cost is not passed on to other customers.

Enrollment is projected at 400 customers. Currently National Grid has 57 customers enrolled into the On Track Program.

Response: WILEY 1-2 (continued)

Payment Plan - Balanced Billing

The Company offers a Balanced Billing Plan.

Niagara Mohawk Power Corporation, d/b/a National Grid.

Payment Plan - Deferred Payment Agreements (DPA)

The Company offers any eligible residential customer a deferred payment agreement (DPA.) All residential customers are eligible for a DPA unless the customer has defaulted on an existing DPA that required payment over a period of at least as long as the standard agreement or the Commission determines that the customer has the resources to pay the bill. A customer will become ineligible for a DPA if he has defaulted on an existing DPA.

If the Company and the customer or applicant are unable to agree upon specific terms, the Company will offer a DPA with the following terms: (a) a down-payment up to 15 percent of the amount covered by the payment agreement or the cost of one-half of one month's average usage, whichever is greater, or if the amount covered by the agreement is less than one-half of one month's average usage, 50 percent of such amount; (b) and monthly installments up to the cost of one-half of one month's average use or one-tenth of the balance, whichever is greater.

The Company also offers DPAs to non-residential customers. A non-residential customer will not be eligible if: he owes any amount under a prior deferred payment agreement; or has failed to make timely payments under a deferred payment agreement in effect during the previous twelve (12) months; or is a publicly held company, or a subsidiary thereof; or a seasonal, short-term or temporary customer; or who the Company can demonstrate has the resources to pay the bill, provided that the Company notifies the non-residential customer of its reasons and of the customer's right to contest this determination through the Commission's complaint procedures; or who during the previous twelve (12) months had a combined total consumption for all its accounts with the Company in excess of 4,000 therms.

Payment Plan - AffordAbility

AffordAbility began in the mid 1990’s and was revised in 2001. It is a payment agreement with arrears forgiveness that is targeted toward low-income customers with high energy usage.

Response: WILEY 1-2 (continued)

The Program is funded through rates and provides for electric and gas customers.

An account enrolled in the program is placed on an initial 12-month payment agreement. Under the terms of the payment agreement, the customer is responsible for paying a percentage of their average bill. A customer receiving electric and gas service is responsible for 92.5% of the average monthly bill. The remaining incremental bill amounts representing 5 and 7.5% discounts, respectively, and any other deviations in the customer's monthly payment amount, positive or negative, are transferred to the customer's arrears.

A component of the AffordAbility program provides for arrears forgiveness. Participants who complete 12 monthly payments and receive a Home Energy Assistance Program (HEAP) grant applied to their National Grid account will receive 50% arrears forgiveness up to $250 per year. In addition, participants successfully completing the program may enroll for another AffordAbility Payment Agreement.

Boston Gas Company, Essex Gas Company, and Colonial Gas Company, d/b/a National Grid.

Payment Plan - On Track

On Track is an 18-month program for low income customers, which began in 2003. The program is designed to educate consumers on efficient energy use and to encourage timely, regular bill payment through behavior modification techniques that include financial and energy management education, consistent customer representative support, and social service referrals. Customers must meet specific program criteria to be eligible. The criteria are as follows: Household gross income must be under 250% of the Federal Poverty Level (FPL), which includes customers that have received or will receive a Fuel Assistance grant during the enrollment year. The account must be for heating in a one or two family home. The account holder must be primarily responsible for payment of the gas bill. The customer can receive other public assistance (outside of HEAP) that covers their gas costs. The customer must be determined financially capable of making at least the minimum deferred payment agreement in addition to their current bills via enrollment in level payment Plan.

Arrears Forgiveness is provided if the terms of the DPA (Deferred Payment Agreement) are kept; customers will be granted allowances up to a maximum amount of $400. The allowances are applied four times over the course of the

Response: WILEY 1-2 (continued)

program in the amount of $100 each. The maximum annual estimated cost of this program is of $140,000.

The OnTrack program is available in Massachusetts to the first 350 customers who qualify. Currently, National Grid has 365 customers enrolled in this program. This cost is not passed on to other customers.

Payment Plan - Arrearage Management Program (AMP)

The National Grid Gas Arrearage Management Program (AMP) is a 24-month program for low income customers. In order to be considered for eligibility, a customer's household income cannot exceed 200% of Federal Poverty Level or Fuel Assistance eligible, whichever is higher. The program is designed to assist those low income customers that have an account in arrears in making timely utility payments.

Arrearage Management Program customers are eligible to receive up to $1196 in arrears forgiveness for heating accounts and $400 in arrears forgiveness for non-heating accounts. Enrollment is limited to 3,330 qualifying customers (enrollment is done through the CAP Agencies). Currently National Grid has 581 customers enrolled in this program. Consumer Advocacy has designated two customer service representatives who work with Community Action Program agencies to administer the program

Customers must pay a 50% down payment to have service restored and must also pay off in full any prior bad debt accounts they may have with National Grid (no matter how many times they have been terminated in the past).

The AMP costs are recovered through the Local Delivery Adjustment Clause.

Payment Plan - Residential Assistance for Families in Transition (RAFT) Program

RAFT is a state-funded is once in a lifetime 12-month program that helps low-income families avoid homelessness by providing assistance to keep or obtain a home. Families can receive up to $3,000 in financial assistance toward certain household expenses, including security deposits, first/last month's rent and utility arrears.

RAFT pays 50% of the account balance and National Grid then grants an allowance of 25% of the balance and the customer is given a Deferred Payment Arrangement for the remaining 25% (enrollment is done through the CAP

Response: WILEY 1-2 (continued)

Agencies.) Consumer Advocacy has designated two customer service representatives who work with the CAP Agencies under the auspice of the Massachusetts DHCD to administer the program. Currently, National Grid has 119 customers enrolled in this program.

RAFT will pay for half of whatever balance the customer owes on the account to have their service restored. After that, the customer is entitled to a one-time 12-month agreement. Should the customer default and be terminated, the Company will require whatever reinstatement amount is due at that time.

Prepared by or under the supervision of: Peter Czekanski

Data Request WILEY 1-3

Request:

Please compare the proposed gas discount with the existing electric discount provided by NG to low-income customers, including *inter alia*:

- Eligibility for the discount;
- The percentage of the discount;
- The charges to which the discount applies;
- The average dollar amount of the discount.

Response:

The Company's proposed low-income gas discount will be available to any gas customer who is receiving grants from the Low Income Home Energy Assistance Program (LIHEAP). The discount is a reduction of 10% from the distribution charges of the Residential Heating or Residential Non-Heat rates. The average dollar amount of the discount is approximately $54 per year (please see response to Data Request WILEY-1-7). In addition, LIHEAP gas customers also receive supplemental LIHEAP funds averaging approximately $100 per year as part of the $1,585,000 funded by all firm gas customers.

The Narragansett Electric Company's Low Income Residential Rate A-60 is available to any customer who is the head of a household or principal wage earner and is receiving Supplemental Security Income from the Social Security Administration, is eligible for LIHEAP, or one of the following from the appropriate Rhode Island agencies: Medicaid, Food Stamps, General Public Assistance or Family Independence Program.

The low income discount is provided through the distribution charges and was designed to provide the average low income customer with a reduction of approximately 50% from the distribution charges of Regular Residential Rate A-16.

The discount for a Rate A-60 customer using 500 kWh per month, based on rates currently in effect, is $11.46 per month.

In addition to the discount provided through base distribution charges, Rate A-60 customers are currently receiving an additional credit of $0.01360 per kWh applicable to the first 450 kWh consumed per month. In Docket No. 3710, filed in November 2005, the Company proposed to use $8 million of the proceeds from a settlement agreement filed in that docket to fund a four-year enhanced low-income credit program. The Commission has subsequently approved these incremental credits for 2006, 2007 and 2008. The current credit of $0.01360 per kWh provides an additional discount of $6.81 per month to the 500 kWh customer.

Prepared by or under the supervision of: Peter Czekanski

Data Request WILEY 1-4

Request:

Please describe the circumstances under which the electric discount was instituted, including *inter alia*:

- The date it was adopted;
- The party(ies) proposing the discount;
- The authority adopting the discount, including any written decision stating reasons why the discount was adopted.

Response:

The Narragansett Electric Company has offered some form of discounted rates to low-income customers since 1978. However, the present Rate A-60 charges were approved by the Commission as part of a comprehensive rate plan settlement in Docket No. 3617 between the Company, the Division of Public Utilities and Carriers, the Department of the Attorney General, The Energy Council of Rhode Island, the United States Department of the Navy and People's Power & Light. The settlement was approved by the Commission pursuant to Open Meeting decisions on September 28, 2004, October 7, 2004 and by written order 18037 issued November 9, 2004. The rates became effective October 28, 2004.

Prepared by or under the supervision of: Peter Czekanski

Data Request WILEY 1-5

Request:

To NG's knowledge, did any of NG's predecessor gas companies provide a discount to low-income customers? If so, please describe that discount.

Response:

The Company is aware that Providence Gas Company (ProvGas), a predecessor gas company, has a Percentage of Income Pilot Program (PIPP) in the late 1980's and early 1990's; however the Company has been unable to locate documents providing a detailed description of the program. In a Commission Order in Docket No. 2082, there is a quote from witness Mr. Arndt that describes the program as follows:

> The PIPP program is a state sponsored fuel assistance program. The plan is designed to subsidize the portion of heating charges that are current for qualified applicants. If the applicant has stayed current with their payments for a six month period, ProvGas will begin to write off the amount that the customer has in arrears when they started the program (i.e., at a rate of 1/36th per month starting in the 7th month). The state will only co-pay for a month that the customer has paid. If the customer misses three straight payments, the state considers this individual in default.

Although not technically designed as a "discount" program, as part of a settlement agreement in the Integrated Resource Plan Docket No. 2025 (1996), ProvGas agreed to one-year funding of a supplemental LIHEAP program at up to $800,000 using a portion of the Company's PBR incentives. This program provided a supplemental match to the federal LIHEAP grants given to low income customers in that year only.

In 1997, the Commission approved the Price Stabilization Plan settlement agreement for ProvGas in Docket No. 2581, which included a supplemental LIHEAP program with annual funding of $1,000,000 from customers. The level of funding was increased to $1,300,000 in October 2000, as part of an extension settlement agreement in the same docket.

In November 1999, Valley Gas Company (also a predecessor company), introduced a surcharge mechanism to establish a $240,000 supplement LIHEAP funding program in Docket No. 3030. The program operated in a similar manner to the ProvGas plan and the annual level of funding was increased to $285,000 in December of 2000.

After Southern Union's acquisition of both ProvGas and Valley Gas, the tariffs and supplemental LIHEAP programs were combined in Docket No. 3401 with annual funding of $1,585,000.

Prepared by or under the supervision of: Peter Czekanski

Data Request WILEY 1-6

Request:

Please state the total value of discounts proposed for the average low-income customer, including the value of both the proposed discount and the $1,585,000 LIAP program.

Response:

The total value of discounts proposed for the average low-income customer, including the value of the $1,585,000 LIHEAP program, is approximately $154 per year.

Prepared by or under the supervision of: Peter Czekanski

Data Request WILEY 1-7

Request:

Please describe the proposed discount as a percentage of the average low-income customer's monthly bill: 10% of the customer and distribution charges amounts to what percentage of the average low-income customer's bill?

Response:

At proposed rates, the average residential heating customer would have a total annual bill of $1,512 (gas supply and delivery). A similar customer on the low-income rate would have a total annual bill of $1,458. The proposed discount is $54 or 3.7% of the low-income customer's total bill.

Data Request WILEY 1-8

Request:

Please state the annual amount by which the proposed 10% discount will increase the average customer's bill in each rate class.

Response:

The annual amount by which the proposed 10% discount will increase the average customer's bill in each rate class is shown in the table below.

Rate Class	Annual Increase due to 10% Discount
Residential Non-Heating	$0.45
Residential Heating	$2.21
Small C&I	$3.05
Medium C&I	$26.28
Large Low Load Factor	$138.58
Large High Load Factor	$140.20
Extra Large Low Load Factor	$699.51
Extra Large High Load Factor	$1,363.65

Prepared by or under the supervision of: David Heintz

Data Request WILEY 1-9

Request:

In NG's response to Division Data Request No. 5-19, NG says that "approximately $1.1 million of customer funds is earmarked for low-income customers as part of the Energy Efficiency Program and Surcharge." Please describe this program and state whether it includes any discount for low-income customers.

Response:

The Company provided a copy of its Docket No. 3790 compliance filing in response to Data Request DIV 7-2 (see Attachment DIV-7-2(a)(2)), which provides descriptions of the approved energy efficiency programs and program budgets[1]. A description of the low-income energy efficiency program, referred to as "Single Family Low Income Services," and the approved funding level for that program are discussed in that response.

As shown therein, the Company is funding Single Family Low Income Services with a budget of $1,436,600 in the period July 1, 2007 through December 31, 2008. The description of this program follows:

> **SINGLE FAMILY LOW INCOME SERVICES**
>
> The Residential Low Income Program offers weatherization services to income qualified customers eligible for fuel assistance benefits, who live in 1-4 unit buildings. As had previously been the case with New England Gas in Rhode Island, the Company will contract with the Rhode Island Office of Energy Resources (OER) and local weatherization agencies for the delivery of energy efficiency services to eligible customers. This is the same program model of serving low income customers currently employed by National Grid for its electric efficiency programs.
>
> Eligible measures provided through the program will include an energy audit, attic insulation, wall insulation, air sealing, heating system replacement (on a qualifying basis) safety inspections, low-flow showerheads and aerators, and funding the installation of CO detectors when DOE funds are not available. The Company will market the program via Company brochures, bill inserts, and the National Grid website. The program may also be marketed through direct contact with eligible customers by OER and local CAP agencies to customers it

[1] The Rhode Island Public Utilities Commission approved the Company's ongoing energy efficiency programs in Order No. 19024.

Prepared by or under the supervision of: Carol White serves through state, federal, or local low income programs (Attachment DIV-7-2(a)(2), at pages 11-12).

Data Request WILEY 1-10

Request:

According to the testimony of Peter Czekanski at pp 10-11, low income customers who are participating in LIHEAP are "easy to identify" based on "established processes for coordination with OER."

- Given these facts, is there any reason why NG cannot get a regularly-updated list of eligible customers from OER, rather than requiring each customer to "annually certify through forms provided by the utility" (Czekanski at 11) that the customer is eligible for a discount due to LIHEAP participation?
- If the customer is required to provide certification of eligibility as NG proposes, does NG plan to confirm eligibility by checking with OER? If so, what purpose does the customer certification serve?

Response:

Please see the Company's response to Data Request DIV 6-39(b).

Prepared by or under the supervision of: Peter Czekanski

Data Request WILEY 1-11

Request:

According to the testimony of Alan V. Feibelman and Richard J. Levin at page 10, as part of the National Grid / KeySpan merger, NG paid executive severance and options of $120 million which NG has included as a CTA in this rate increase request. As to these payments, please state:

- The total dollar amount of the payment / options package given to each such executive (without identifying the executives);
- The total dollar amount of the this $120 million figure that NG is proposing to allocate to customers in this docket;
- The annual dollar amount of this $120 million figure that NG is proposing to allocate to customers each year for the next ten years.

Response:

As discussed in the testimony of Mr. Feibelman and Mr. Levin (at page 11, lines 1-5), and as shown on Schedule NG-AVF/RJL-2 (bottom of the schedule), executive severance and options costs ($120 million) are **excluded** from the CTA incorporated into the rate request.

As a result, National Grid is not proposing to allocate any of the $120 million costs to customers.

Prepared by or under the supervision of: Rick Levin

Data Request WILEY 1-12

Request:

According to DAH-5, the proposed percentage rate increase for every class except C&I LLF Extra-Large and C&I HLF Extra-Large goes up with decreases in usage.

a. Why?
b. How is this consistent with NG's stated commitment to energy efficiency?

Response:

a. As a customer's usage increases, the percentage of the total bill representing the base-rate portion decreases. For example, at 40 therms, a residential customer's November total bill (assuming proposed rates) is $74 with base rates making up $30 or 40.5% of the total bill. At 62 therms, a residential customer's November total bill would be $105, with base rates making up $32 or 30.5% of the total bill. Since the overall change in the total bill is almost solely related to the base rates and base rates represent a smaller portion of the bill as usage increases, the percentage change decreases as consumption increases.

b. This is quite consistent with NG's stated commitment to energy efficiency. Because a customer's total bill increases with usage, mainly as a result of the volumetric gas cost component, each therm saved through the installation or use of energy efficiency measures will lower the customer's bill.

Prepared by or under the supervision of: David Heintz

Data Request TEC-RI 1-1

Request:

Concerning the $20.04 million rate increase, please begin by adjusting the $20 million upward for factors which reduced the revenue requirement from what it otherwise would have been, including but not limited to merger savings. Of this increase, how much of it is a result of the increased capital investment proposed in this filing, how much is return on the increase in rate base since the last rate case, how much of it is a result of the new Gas Marketing Program, how much is a result of increases in the cost of doing business, and how much is other items?

Response:

The following is an itemization of the components of the $20.04 million rate increase request.

	$ Millions
Adjusted Test Year Return Deficiency	$18.53
Return on Increased Rate Base to Rate Year	4.00
Revenue Adjustments	(2.56)
O&M Expense Adjustments	0.21 (Note 1)
Depreciation Expense Adjustment	(0.91)
Taxes Other Than Income Tax Adjustment	0.03
Bad Debt Adjustment	0.74
Total	$20.04

(1) Please refer to Attachment NG-MDL-1, Page 5 of 33 for a listing of individual expense adjustments aggregating $216,301.

The O&M expense adjustments include the impact of the Company's proposed 50/50 sharing of merger savings as follows:

	National Grid/ Southern Union Transaction	National Grid/ KeySpan Transaction
Demonstrated savings included in Rate Year	$2,439,354	
Projected savings yet to be realized		$6,400,000
Ten Year amortization of Costs to Achieve	(158,152)	(1,500,000)
Net Synergy savings	2,181,201	4,900,000
Company Savings allowance (50%)	(1,140,601)	(2,450,000)
Customer Share of net synergies	$1,140,601	$2,450,000

Prepared by or under the supervision of: Mike Laflamme

Data Request TEC-RI 1-2

Request:

The new rates represent an increase of 16-24% in distribution rates depending on the class. Please show the contribution to the rate increase made by increases in revenue requirements, and the contribution made by reductions in use per customer relative to a reasonable benchmark of your choosing.

Response:

As discussed in the pre-filed direct testimony of James D. Simpson at page 26 lines 12 through 19, the impact on Company revenues of the declining Residential Heating NUPC that the Company experienced between June 2004 and December 2007 was $7.6 million.

Attachment TEC-RI 1-2 shows the impact of the decline in normalized revenues per customer on Company revenues, by class and for the total Company. If the normalized RPC had remained at the levels incorporated into rates in the Company's most recent rate case, Docket No. 3401, the Company's increase to firm gas services in the present proceeding would have been approximately $10.4 million less than the $20.3 million that is being requested.

Prepared by or under the supervision of: James Simpson

		Rate Year Docket No. 3943			Rate Year Docket No. 3401				
Line	Rate Schedule	Current Distribution Revenue	Average Customers	Current Distribution Revenue per Customer	Target Revenues	Average Customers	RPC	Difference	Total Class Difference
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
		Attachment NG-DAH-3, Col. B	Attachment NG-DAH-4, Col. C	(B) / (C)	Compliance filing	Compliance filing	(E) / (F)	(G) / (D)	(H) x (D)
1	Residential Non-Heat	$5,133,293	30,190	$170.03	$6,550,715	35,809	$182.94	$12.90	$389,599
2	Residential Heat	$82,164,785	195,950	$419.32	$81,617,893	180,022	$453.38	$34.06	$6,674,226
3	Small C/I	$10,491,164	18,589	$564.37	$11,164,537	18,427	$605.88	$41.51	$771,561
4	Medium C/I	$14,650,241	4,517	$3,243.18	$14,824,179	4,137	$3,583.74	$340.56	$1,538,390
5	Large Low	$6,730,933	441	$15,262.89	$5,546,792	329	$16,847.34	$1,584.45	$698,742
6	Large High	$1,812,681	163	$11,120.74	$1,799,717	152	$11,872.02	$751.28	$122,458
7	X-Large Low	$1,108,782	38	$29,178.47	$868,189	34	$25,864.20	-$3,314.27	-$125,942
8	X-Large High	$3,473,673	74	$46,941.53	$2,534,746	50	$51,111.26	$4,169.73	$308,560
9	Total[1]	$125,565,552	249,962		$124,906,768	238,959			$10,377,594

Note: Residential class totals include Low Income customers.

[1] Totals do not include NGV or Gas Light classes

Data Request TEC-RI 1-3

Request:

Customer conservation does not increase distribution revenue requirements, but rather should have the opposite effect over time. What are the company's estimates for system cost savings resulting from customer conservation levels, both in the last 10 years and over the next 10 years?

Response:

Customer conservation will not decrease distribution revenue requirements over time. Under certain circumstances, extended periods of significant customer conservation will likely reduce the rate at which annual revenue requirements would increase; however, the Company has not made any estimates of the impact of customer conservation on revenue requirements over the past ten years or over the next ten years. Please see the Company's response to Data Request TEC-RI-1-44 for further discussion.

Prepared by or under the supervision of: James Simpson

Data Request TEC-RI 1-4

Request:

The $ 7.4 million annualized lost revenue from residential heating annualized since 2004 (Stavropoulos page 4 of 28) – please show the calculation. Please answer the question – compared to what? Please compare to the use per customer in the last rate case, and please compare to use per customer that year held constant. Also, please calculate for the other classes.

Response:

The calculation of the annualized lost revenues of $7.6 million in the period June 2004 through December 2007 is provided in the pre-filed direct testimony of James D. Simpson, at page 26, footnote 18. The decrease in revenues is compared to the revenues that would have resulted if Residential Heating NUPC had remained at the June 2004 level of 1,025.4 therms, rather than decreasing to 908.2 therms as of December 2007.

The Residential Heating use per customer in the Company's last rate case was 1029.3 therms. Actual 12-month rolling UPC values and the comparison to the weather normalized UPC values in the Company's last rate case are included in Attachments NG-JDS-4, 5, and 6 and in response to Data Request TEC-RI-1-69. Calculations to compare test year normalized RPC to approved RPC from the Company's last rate case, Docket No. 3401, have been provided in the response to Data Request TEC-RI-1-2.

Prepared by or under the supervision of: James Simpson

Data Request TEC-RI 1-5

Request:

What is the projected impact of the low income distribution rate program on company uncollectibles/receivables for gas distribution revenue?

Response:

The pro forma uncollectible expense was based on a historical average of total company revenues and uncollectible amounts. The Company does not anticipate that the low-income discount would have any net impact on the level of uncollectibles in a given annual period.

Prepared by or under the supervision of: David Heintz

Data Request TEC-RI 1-6

Request:

Will the benefits of reduce uncollectibles resulting from the low income rate accrue to customers or to National Grid's bottom line?

Response:

The proposed uncollectible rate is a representative rate based on a five-year average of net-write-offs. This percentage is applied to pro-forma revenues, which includes the low income revenues, to obtain the uncollectible expense. Because the amount of uncollectible expense included in rates is based on a representative level rather than actual level, there is no basis for the assumption that the availability of the low-income rate will have the effect of reducing uncollectible expense. Any number of factors could occur over time causing uncollectible expense to increase or decrease and these changes would be reflected in the representative level of historical writeoffs so that any one factor occurring in the future would not necessarily have any incremental impact on the level of uncollectible expense.

Prepared by or under the supervision of: David Heintz

Data Request TEC-RI 1-8

Request:

Please explain the method you used to allocate the expenses of the proposed low income rate to the other rate classes.

Response:

The low-income classes are not separate classes in the cost of service study. Therefore, there is no allocation of expenses to or from the proposed low-income rate to the other rate classes. Rather, the proposed low-income rates are implemented through rate design. The low-income rates are determined as a discount from the full cost residential heating and non-heating rates. The dollars associated with the discount are allocated to the other rate classes on a volumetric basis. See Attachment NG-DAH-3, page 1, columns (F) and (G).

Data Request TEC-RI 1-9

Request:

When it comes to merger "savings" from the NGrid/Southern Union merger, the adjustment to the actual historic rate year revenue requirements is to INCREASE revenue requirements by 50% of the documented savings, because this represents what National Grid is claiming as the company's share of those savings. There was never a time when rates were reduced because of those "savings". How can the customers be assured that these "savings" are real?

Response:

The documented savings detailed on Attachment NG-MDL-1, at page 20 of 33 have mitigated the requested rate adjustment in this proceeding in the form of lower test-year expenses, which form the basis for the underlying Rate Year expenses included in the cost of service. Consequently, customers are receiving the benefit of these savings as a result of a lower cost of service than otherwise would have resulted absent the merger.

Prepared by or under the supervision of: Mike Laflamme

Data Request TEC-RI 1-10

Request:

For the $5 million + of labor savings from the NGrid/Southern Union merger, please provide a list of job titles, annual salary, and allocated overhead for the positions eliminated.

Response:

The demonstrated labor savings amount associated with the National Grid/Southern Union transaction were not developed by accumulating a list of employees eliminated as a result of the merger. As shown on Attachment NG-MDL-1, Page 20 of 33, the calculation of the labor savings totaling $5,062,430, was based on a comparison of total expense payroll for the pre-merger 12-month period ending June 30, 2006 to steady state expense labor as of September 30, 2007, which is included in this proceeding. Consequently, the requested list does not exist.

Prepared by or under the supervision of: Mike Laflamme

Data Request TEC-RI 1-12

Request:

Will the gas usage increases by month from the Gas Marketing Program have the effect of lowering the GCR, increasing it, or leaving it the same?

Response:

Please see the Company's response to Data Request DIV-8-19, stating that the incremental impact of the proposed programs will add less than 1% of the annual load forecasted by the Company and at least a portion of the increase will be offset by expected reductions. Although daily spot prices in New England have shown a tendency to spike higher during periods of exceptionally cold weather in recent winters, the impact of these customers will be quite small, especially when compared to other loads on the system. Moreover, the Company has adequate pipeline capacity to meet its projected requirements including the additional load associated with this program. Because the Company has no plans to add capacity beyond what it is already planned, the additional load would have no impact on the prices for pipeline capacity to Rhode Island. Likewise, the Company has adequate local peaking resources and does not anticipate that the small net increase in load from this program will result in reduced availability or higher prices for its peaking supply resources. Therefore, to the extent either past or future declines in customer use act as a source of capacity, this program would be expected to reduce costs to customers.

Prepared by or under the supervision of: Gary Beland

Data Request TEC-RI 1-13

Request:

In Attachment NG-PCC-2, there are proforma adjustments in the billing determinants of the Extra Large High Load Factor class, Transportation Service, (1,087, 143 Dt.) and the Extra Large Low Load Factor class, Transportation Services. How many customers moved into each of these two classes. What would the Revenue per customer target have been without these customers? What happens to these rates under the decoupling scheme if these customers return to non-firm service?

Response:

The forecast for the rate classes with transportation service was based on the combination of the sales and transportation services within each rate class. The resulting forecast was then split between sales and transportation using the most recent transportation customer counts as the base forecast with adjustments then added to incorporate conversions from non-firm to firm service and marketing program additions as appropriate. These changes are reflected in the proforma adjustments referenced in the question above. Similarly, the proposed revenue decoupling mechanism monthly revenue per customer (RPC) targets are based on the combination of the sales and transportation services within each rate class. Attachment TEC RI-1-13(a) shows the number of customers that "moved into each of these two classes" based on a month-by-month comparison of all customers in the two extra large rate classes during the test year (October 2006 through September 2007) and the rate year (October 2008 through 2009).

Attachment TEC RI-1-13(b) shows a comparison of the RPC monthly targets based on the test year number of customers and base revenues versus the rate year number of customers and proposed base revenues. The XLL Revenue per customer target would have been $25,746 (Attachment B, Line 3) without these customers and the XLH Revenue per customer target would have been $44,612 (Attachment B, Line 17) without these customers. Under the decoupling mechanism, the RPC targets do not change as the number of customers increase or decrease and hence under the hypothetical case of the XLL and XLH Rate year customer counts reverting back to the test year levels, there would be a revenue decoupling true-up of $35,745.82 collected from Extra Large Low Load Factor customers and a credit of ($11,393.57) to Extra Large High Load Factor customers assuming that there was no change in usage.

Prepared by or under the supervision of: Peter Czekanski

National Grid
Rhode Island - Gas

Comparison of Extra Large Rate Classes in Test Year vs Rate Year

Attachment A to TEC-RI 1-13
Docket No. 3943

Customers

Line														
1	Normal	Oct-06	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Average
2	XLL sales	7	7	7	6	6	6	6	6	6	6	6	7	6
3	XLL Transportation	25	25	25	27	27	27	27	27	28	28	28	27	27
4	Total	32	32	32	33	33	33	33	33	34	34	34	34	33
5														
6	Rate Year	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Average
7	XLL Sales	7	7	7	7	7	7	7	7	7	7	7	7	7
8	XLL Transportation	31	31	31	31	31	31	31	31	31	31	31	31	31
9	Total	38	38	38	38	38	38	38	38	38	38	38	38	38
10														
11	Difference	6	6	6	5	5	5	5	5	4	4	4	4	5
12														
13														
14														
15	Normal	Oct-06	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Average
16	XLH sales	15	16	16	16	15	16	16	16	15	15	11	12	15
17	XLHTransportation	48	47	48	47	50	49	49	50	52	52	53	57	50
18	Total	63	63	64	63	65	65	65	66	67	67	64	69	65
19														
20	Rate Year	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Average
21	XLH sales	11	11	11	11	11	11	11	11	11	11	11	11	11
22	XLHTransportation	63	63	63	63	63	63	63	63	63	63	63	63	63
23	Total	74	74	74	74	74	74	74	74	74	74	74	74	74
24														
25	Difference	11	11	10	11	9	9	9	8	7	7	10	5	9

Comparison of Extra Large Rate Classes in Test Year vs Rate Year

Revenue Per Customer

Line	Normal	Oct-06	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Total
1	XLL Number of Customers	32	32	32	33	33	33	33	33	34	34	34	34	33
2	XLL Base Revenue	$61,236	$72,406	$88,725	$89,435	$93,976	$95,397	$73,668	$58,399	$56,342	$54,920	$54,698	$52,568	$851,770
3	RPC	$1,914	$2,263	$2,773	$2,710	$2,848	$2,891	$2,232	$1,770	$1,657	$1,615	$1,609	$1,546	$25,746
4														
5	Rate Year (proposed rates)	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Total
6	XLL Number of Customers	38	38	38	38	38	38	38	38	38	38	38	38	38
7	XLL Base Revenue	$111,916	$83,892	$99,578	$107,933	$106,695	$102,399	$85,716	$73,798	$64,441	$63,029	$63,446	$60,478	$1,023,321
8	RPC	$2,945	$2,208	$2,620	$2,840	$2,808	$2,695	$2,256	$1,942	$1,696	$1,659	$1,670	$1,592	$26,930
9														
10	Difference	$1,032	($55)	($152)	$130	($40)	($196)	$23	$172	$39	$43	$61	$45	$1,183
11														
12		$33,009.05	($1,760.11)	($4,869.84)	$4,296.29	($1,319.82)	($6,471.55)	$769.58	$5,688.74	$1,315.74	$1,474.37	$2,069.47	$1,543.89	$35,745.82
13														
14	Normal	Oct-06	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Total
15	XLH Number of Customers	63	63	64	63	65	65	65	66	67	67	64	69	65
16	XLH Base Revenue	$224,463	$255,044	$258,256	$240,820	$261,569	$265,844	$243,836	$235,738	$231,191	$232,473	$221,926	$232,316	$2,903,476
17	RPC	$3,563	$4,048	$4,035	$3,823	$4,024	$4,090	$3,751	$3,572	$3,451	$3,470	$3,468	$3,367	$44,612
18														
19	Rate Year (proposed rates)	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Total
20	XLH Number of Customers	74	74	74	74	74	74	74	74	74	74	74	74	74
21	XLH Base Revenue	$381,121	$270,351	$274,277	$285,635	$274,442	$278,708	$272,896	$259,612	$251,211	$250,723	$254,412	$241,787	$3,295,175
22	RPC	$5,150	$3,653	$3,706	$3,860	$3,709	$3,766	$3,688	$3,508	$3,395	$3,388	$3,438	$3,267	$44,529
23														
24	Difference	$1,587	($395)	($329)	$37	($315)	($324)	($64)	($64)	($56)	($82)	($30)	($100)	($82)
		$100,004.88	($24,880.31)	($21,043.46)	$2,355.74	($20,505.08)	($21,032.92)	($4,130.05)	($4,192.16)	($3,743.20)	($5,467.04)	($1,894.00)	($6,865.96)	($11,393.57)

Data Request TEC-RI 1-14

Request:

Since the company is proposing to exclude new C&I customer additions in the future from the decoupling mechanism, why should the pro-forma adjustments described in TEC-RI (13) be made at all?

Response:

The additions reflected in the pro-forma adjustments for the large and extra large classes are associated with non-firm service customers that have switched to firm service. These changes were known and measurable and have been included in the calculation of the rate-year revenues and rate design and they will be subject to the revenue decoupling mechanism. Future conversions from non-firm to firm service will also be subject to the revenue decoupling mechanism unless the Company is required to make additional investments to provide firm service to that load.

Prepared by or under the supervision of: Peter Czekanski

Data Request TEC-RI 1-15

Request:

Did the addition of these customers to these two classes increase the allocated cost of service to these classes? And if so, was it done on a per customer basis or a volume basis? If the latter, please explain.

Response:

The addition of customers to a rate class would tend to increase the amount of costs allocated to the class. Costs are allocated to the rate classes by:

- Direct assignment;
- Demand, customer, or volumetric allocation factors, or;
- An internal allocation factor.

The pre-filed direct testimony of David Heintz explains the process used to develop the class cost of service study. Workpapers DAH-1, at pages 29–33 detail the allocation factor used for each cost item. The allocation factors are found in Workpapers DAH-1, at pages 34–40.

Data Request TEC-RI 1-16

Request:

How will the customer counts be monitored to ensure the integrity of the decoupling adjustment?

Response:

The customer counts are captured as part of the Company's monthly close when a snapshot is taken of the Company's billing system to make a count of active services. These records are retained by the Company as part of its financial reports.

Prepared by or under the supervision of: Peter Czekanski

Data Request TEC-RI 1-17

Request:

If additional customers move from non-firm to firm service, how will this be treated under the company's decoupling proposal?

Response:

If a customer switches from non-firm to firm service, the customer's base distribution revenues will be included in the calculations of actual billed RPC and compared to the Target RPC for the class that it switched to in the months following the switch, unless (1) the customer switched to a Large or Extra Large rate classification, and (2) the Company is required to make additional investments to provide firm service to that customer.

Prepared by or under the supervision of: James Simpson

Data Request TEC-RI 1-20

Request:

In Attachment NG-PCC-2, why is the proforma adjustment negative for Sales Service Large Low Load Factor and Extra Large High Load Factor?

Response:

The forecast for the rate classes with transportation service was based on the combination of the sales and transportation services within each rate class. The resulting forecast was then split between sales and transportation using the most recent transportation customer counts as the base forecast with adjustments then added to incorporate conversions from non-firm to firm service and marketing program additions as appropriate. The proforma adjustment for Sales Service Large Low Load and Extra Large High Load is negative reflecting the change in the mix of sales and transportation customers at the end of the test year, compared to the average for the test year, which is used as the base for the forecast going forward.

Prepared by or under the supervision of: Peter Czekanski

Data Request TEC-RI 1-21

Request:

Do the "growth" adjustments account for any activity in the proposed Gas Marketing Program? Please explain.

Response:

Yes. As described in the testimony of Mr. Czekanski at page 9 lines 8 through 11, the incremental customers and associated delivery quantities for the residential, small C&I and medium C&I rate classes were added to the forecast and are reflected in the rate year billing determinants and revenues.

Prepared by or under the supervision of: Peter Czekanski

Data Request TEC-RI 1-22

Request:

Actual throughput for Sales Service in test year was 26,342,521 Dt. The proforma adjustment is 236, 733 Dt or an adjustment of less than 1%. On the other hand, the values for Transportation Service are 7,254,430 and 1,576,879 or an adjustment of over 21%. In terms of share of actual, the adjustment made to Transportation Service is over 24 times as high as the one made for Sales Service. (a) Please provide an allocated cost of service before and after the proforma adjustments are made. (b) Please provide revenue per customer targets before and after the proforma adjustments are made.

Response:

(a) & (b): The Company did not perform the requested study because the elimination of one adjustment from the cost-of-service study for a particular class of service without analysis of and adjustment for related costs and revenues would produce misleading and incorrect results.

The forecast for the rate classes with transportation service was based on the combination of the sales and transportation services within each rate class. The resulting forecast was then split between sales and transportation using the most recent transportation customer counts as the base forecast with adjustments to incorporate conversions from non-firm to firm service and marketing program additions as appropriate. These changes are reflected in proforma adjustments referenced in the question. The allocated cost of service study was based on the combined sales and transportation data for each rate class as are the proposed revenue decoupling mechanism monthly revenue per customer (RPC) targets. Also please see the Company's response to Data Request TEC-RI-1-13.

Prepared by or under the supervision of: David Heintz

Data Request TEC-RI 1-23

Request:

On what date was Concentric Energy Advisors hired by the Company? Please provide signed contracts.

Response:

Concentric Energy Advisors was initially hired by the Company in November 2007 to conduct an embedded class cost of service study and to develop a proposed rate design. In January 2008, the Company executed a second contract to retain Concentric's services on the development of a revenue decoupling mechanism. The contracts contain confidential and competitively sensitive pricing data. Therefore, the contracts are provided herewith as Attachment TEC-RI-1-23(a) and (b) in redacted format. On this date, the Company is filing a Motion for Confidential Treatment with the Commission and will provide a confidential version of the contracts to the Commission pending the Commission's ruling on the Motion. In addition, the Company will provide a confidential copy of the contracts to the Division and the Office of the Attorney General subject to an executed non-disclosure agreement.

Prepared by or under the supervision of: Peter Czekanski

CONCENTRIC
ENERGY ADVISORS

November 14, 2007

Mr. Peter Czekanski
Director of Pricing
National Grid
100 Weybosset Street
Providence Rhode Island 02903

Dear Peter,

Concentric Energy Advisors, Inc. ("CEA") welcomes the opportunity to provide our expertise and services to National Grid RI in conducting an embedded class Cost of Service Study ("COSS") and rate design services in support of a general rate increase filing with the Rhode Island Public Utilities Commission ("RIPUC"). Provided below are CEA's proposed scope of services, project deliverables, project team and budget.

INTRODUCTION TO CEA

CEA is a management consulting and economic advisory firm focused on the North American energy industry. Based in Marlborough, Massachusetts, CEA specializes in energy market and regulatory strategies, market assessments, regulatory and litigation support, transaction-related financial advisory services, energy commodity contracting and procurement, economic feasibility studies, and capital market analyses and negotiations.

With more than 350 years of combined industry experience, the firm's consultants have held executive positions with management consulting firms, utility companies, regulatory agencies, competitive energy suppliers, and investment banks. CEA consultants have a substantial and successful history of working on a variety of issues for electric, gas and water clients across North America. It is this broad base of experience, combined with rigorous analysis and a highly collaborative approach to working with clients, that enables CEA to deliver pragmatic strategic insights and implementable business solutions that achieve client objectives.

CEA is uniquely positioned to assist companies such as National Grid RI with regulatory and litigation support issues due to the breadth and depth of experience that we provide to our clients. Of particular relevance to National Grid RI, CEA's experts have provided testimony on more than 250 occasions in administrative and civil proceedings on a wide range of energy and economic issues. Clients in these matters have included gas distribution utilities, gas pipelines, gas producers, oil producers, electric utilities, large energy consumers, governmental and regulatory agencies, trade associations, independent energy project developers, engineering firms, and gas and power marketers. Testimony sponsored by CEA's staff ranges from broad regulatory and economic policy to virtually all elements of the utility ratemaking process.

David Heintz, CEA's project manager for this engagement, has prior experience with National Grid RI as he provided the cost of service and rate design services in National Grid RI last rate case, Docket No. 3401. He understands the nature of the regulatory review process in Rhode Island and the interest and concern that the RIPUC and intervenors place on rate design that is supported by the COSS. We also understand, through this first hand experience, the strategic importance of rate design in addressing such issues that are of concern to the Company as financial stability, opportunities for growth, and competition from alternate energy sources. CEA will work with National Grid RI to ensure proper alignment between the COSS and National Grid RI's rate design goals and objectives.

SCOPE OF SERVICES

CEA understands that National Grid RI anticipates making a general rate increase filing with the RIPUC in February 2008 and is in need of consulting support to make that filing. CEA proposes to assist National Grid RI in its filing by performing a COSS which conforms to the RIPUC's conventions as observed by past National Grid RI filings. CEA's work effort will include the following tasks:

Task 1 – Conduct a Project Initiation Meeting and Situational Assessment.

The purpose of this task is to meet with National Grid RI staff to initiate this project and to conduct initial fact-finding. The Kick off meeting together with ongoing discussions on company goals and objectives for this rate case is an opportunity to specify and clarify the key factors influencing National Grid RI's costing, ratemaking and regulatory options and the broader strategic and operating context within which this project is being conducted. As part of this effort, we will review prior embedded cost of service studies prepared by National Grid RI to identify any consistency issues or sensitivities that might influence our choice of costing approaches in this project. A key deliverable from this task will be the specification of the configuration of the COSS model. The preferred configuration will be influenced by a variety of considerations, including: availability of cost and load data, how the results will be used for rate design purposes, and differences in preliminary cost levels among service classifications.

Task 2 – Perform the Special Studies Required to Support the COSS.

CEA believes that many consulting firms have developed COSS models that could meet National Grid RI's needs. CEA is unique, however, in the breadth and depth of our experience with gas distribution companies and with preparing and testifying to Cost of Service Studies. This experience is especially useful and beneficial in preparing the underlying special studies that are a key component of a COSS. Some of these special studies require significant expert judgment; as a result of CEA's extensive experience in preparing special studies, we produce high quality analyses because we ask the right questions to the right people, in a manner that minimizes the impact on the Company's ongoing operations. In particular, special studies to (1) determine class contributions to system design day, (2) assign meter and service costs to rate classes, and (3) determine directly assignable costs to large customer groups or those costs related to the administration of transportation services will typically require significant effort. The results of from the special studies will be used to derive the appropriate allocation factors to support the chosen allocation methods.

Task 3 – Configure the COSS Model for National Grid RI and Run the Model

We will modify CEA's proprietary Microsoft Excel® based COSS model for National Grid RI rate classes and to produce the results in the detail to meet National Grid RI's business and regulatory needs[1]. We will also prepare multiple runs of the model to test the accuracy of the data entry process, to validate the reasonableness of the allocators and special study results and to provide insight and guidance for the design of the proposed rates.

Task 4 – Provide Written Testimony and Exhibits supporting the COSS.

CEA's project team members will support the Company's overall COSS results as a part of National Grid RI's general rate case filing before the RIPUC, through the preparation of pre-filed direct testimony and supporting exhibits, and will serve as expert witnesses on behalf of the Company.

Task 5 – Rate Design Support

CEA will prepare the needed rate design proposals and models as needed by National Grid RI. We understand that the Company desires to make changes to its current Purchased Gas Adjustment clause and may wish to address other rate design issues. CEA is willing to offer its assistance in the area of a revenue decoupling mechanism if that is desired by the Company. CEA's services in the area of rate design would include:

- Develop the exhibits on ratemaking mechanisms and rate design needed to support the filing; and
- Provide written testimony on the Company's chosen ratemaking mechanism(s), preferred rate design and any proposed rate structure modifications, and serve as an expert witness on behalf of the Company[2].

1 For example, for this project, CEA will develop cost-based non-firm rates, to comply with the RIPUC's decision in Docket No. 3887, October 11, 2007. These cost-based non-firm rates could be developed by modifying the COSS model, or alternatively, through analysis performed outside the COSS model.

2 CEA understands that National Grid may propose to implement a decoupling mechanism in this proceeding. CEA would be pleased to assist National Grid with a decoupling proposal; we have significant experience and expertise in decoupling and we are already very familiar with the positions that National Grid has taken in other states on decoupling.

Task 6 – Provide Post-Filing Support

CEA will support National Grid RI's post-filing activities associated with its rate case proceeding before the RIPUC. This task will include, but not be limited to, responding to interrogatories and data requests; providing expert witness testimony in hearings before the RIPUC; reviewing and responding to intervener positions; participating in settlement discussions and meetings; and assisting in the preparation of legal briefs and other regulatory documents, as required.

COST OF SERVICE MODEL

CEA's Microsoft Excel® based COSS model can be easily configured to comply with the RIPUC's standards. The model has the flexibility to use a variety of Chart of Accounts (e.g. FERC, or company specific) and contains many features that promote ease of use, efficiency and adaptability. These include:

- **Expandable customer class specification** – The model is configured to allow up to 19 rate classes. Additional customer classes can be created with minor modifications to the model.
- **Automated functionalization, classification, and allocation** – The model automatically changes the allocation percentages whenever the user changes a functionalization, classification, or allocation factor of an account. There is no need to recode the allocation percentages or change cell formulas.
- **Cost tracking** – Costs can be tracked on a functional basis allowing for the calculation of functional revenue requirements and functional unit rates. There are currently options for 15 different (external) functional categories built into the model. Additional functional categories can be created with minor modifications to the model.
- **Information linked, not transferred** – Rather than transferring or copying tables of data between single worksheets, the CEA model uses the linking capabilities of the software to directly reference information in one area that is used later in the cost of service process.
- **Color Coding** – Cells are shaded specific colors to indicate factor related inputs, data related inputs, data transferred from another worksheet, data checking and formulas that shouldn't normally be modified. Text is shaded blue to indicate an item that is an external user input and black to indicate that a cell is calculated.
- **Centralized inputs** – Instead of having external input data located throughout the model, inputs have been centralized to three worksheets. This has been done to simplify data entry and to help prevent the user from forgetting to update information in a particular file or worksheet.
- **User-friendly buttons for running macros** – Instead of having to remember commands to run the macros to calculate the model, conduct error checks and print various pages, the macros run through toolbar icons or by buttons on a centralized controls tab.

The model uses two types of allocation factors, external and internal. External factors are derived by from rate schedule specific information, e.g. volumes, customers, revenues, or from special studies that are performed outside the COSS model, e.g. class specific meter and service costs, meter reading expenses and direct assignments. Internal allocation factors are developed within the model as a result of prior calculations. For example, a functional labor or plant factor can be derived from the labor or plant amounts allocated to a rate class. The model computes income taxes by class based on the net income for the class and the effective statutory income tax rates. As currently configured the model can accommodate two cost scenarios, e.g. base period and test period, but this can be expanded as necessary.

CEA's model keeps track of cost components on a functionalized basis as well as by customer, demand and commodity components. In addition to standard reports for functional rate base, overall revenue requirement and unit cost analysis, the model produces reports showing the return by class at current rates and class revenue requirements at equalized rates of return. Returns by class at proposed rates can be easily produced for internal use by the Company's rate design witness, or if required to be included in the rate case filing. Each of these reports can be customized to meet the specific needs of the Company. At its core, the model is a convenient way to display the costs of serving each rate class.

QUALIFICATIONS OF CEA

CEA has significant experience that is directly relevant to this project. In addition to CEA's extensive regulatory experience, CEA consultants have recently been responsible for the design and preparation of Rate Design and Cost of Service Studies for the following companies:

- Chesapeake Utilities Corporation (DE)
- Chattanooga Gas Company (TN)
- Arkansas Oklahoma Gas Company (AR, OK)
- Atlanta Gas Light (GA)
- Missouri Gas Energy, div. of Southern Union Company (MO)
- Peoples Gas Light & Coke (IL)
- Virginia Natural Gas (VA)
- Puget Sound Energy (WA)
- Terasen Gas (British Columbia, Canada)
- New England Gas Company (MA, RI)
- North Shore Gas Company (IL)
- Oklahoma Natural Gas Company (OK)
- Great Lakes Power (Ontario, Canada)
- Citizens Gas and Coke Utility (IN)
- SEMCO Energy Gas Company (MI)
- Connecticut Natural Gas (CT)
- Southern Connecticut Gas (CT)
- PG Energy – now UGI Penn Natural Gas (PA)

PROPOSED PROJECT STAFF

CEA's Responsible Officer for this project will be Jim Simpson and David Heintz will act as Project Manager. Mr. Heintz will be assisted by Andrew Hickok. Biographical summaries of the primary team members are included below and their full resumes are included in **Attachment A**. Both Mr. Heintz and Mr. Simpson will be available to serve as expert witnesses.

James D. Simpson, Vice President, has over 25 years of experience with regulatory relations, regulated pricing and business strategy; he has held senior executive positions at a natural gas utility and an entrepreneurial company providing a proprietary service to generating companies. As Chief Operating Officer for a major New England gas company, Mr. Simpson was responsible for all regulated business activities including Gas Supply, Operations, Engineering, Marketing and Sales, and Planning. His responsibilities in other positions have included business development, pricing strategy, regulatory affairs, analysis and planning. Mr. Simpson also held staff and director level positions at the Wisconsin Public Service Commission and the Massachusetts Department of Public Utilities; he has an M.S. in Economics from the University of Wisconsin and a B.A. in Economics from the University of Minnesota.

David A. Heintz, Assistant Vice President, has over 25 years of experience working with regulated rates and tariffs at both the federal and state levels. He also provides clients with analyses of natural gas projects, energy markets and related issues. Mr. Heintz's areas of expertise include cost of service, allocation and rate design, tariff terms and conditions, rate case preparation and regulatory issues. Prior to joining Concentric Energy Advisors, Mr. Heintz was a Managing Consultant with Navigant Consulting, Inc. and has worked for the Federal Energy Regulatory Commission, interstate pipelines and a local distribution company. Mr. Heintz holds an MBA from the University of Pittsburgh and a B.S. in Economics from the Pennsylvania State University.

Andrew Hickok, Analyst, joined CEA in 2006. Mr. Hickok has contributed to projects involving litigation support, rate design, regulatory support and strategy, and market assessment. Mr. Hickok also has extensive experience in database development, analysis of environmental and energy policy, and utilization of geographic information systems. His work often involves researching and synthesizing regulatory issues, performing statistical analysis, conducting due diligence, and contributing to the writing of reports and expert testimony. Mr. Hickok has four years of experience in consulting for government and corporate clients. Mr. Hickok holds a B.A. in Geography from Middlebury College.

PROPOSED BUDGET

In performing the above listed COSS and rate design services, CEA will depend on data and supporting documentation supplied by the Company. Since the data required for many of the special studies requires extensive and detailed accounting records (e.g. meter costs by size, type and rate class), CEA assumes that the Company's accounting general ledger, plant records, and customer information system are capable of producing the needed information.

Based on the proposed scope of services, CEA estimates a budget of [redacted] (comprising approximately [redacted] consultant hours) to complete all COSS activities in Tasks 1 through 5 above, up to and including the filing of Company's general rate case. This budget does not include any efforts related to a decoupling mechanism; CEA would be happy to provide a separate budget estimate if National Grid wants CEA to assist in designing or supporting a decoupling proposal. In addition to our professional fees, CEA will invoice National Grid RI for direct, out-of-pocket travel expenses CEA staff will incur during the course of this assignment. Post-filing activities, as described in Task 6, will be billed on a time and materials basis at the rates shown in **Attachment B**. CEA's standard terms and conditions are included as **Attachment C** to this letter.

REDACTED

Peter, I would again like to thank you for the opportunity to provide this proposal. Should you have any questions or require clarification with any aspect of this letter, please do not hesitate to contact me at (508) 263-6224 or David Heintz at (508) 263-6230.

Very truly yours,

Concentric Energy Advisors, Inc.

James D. Simpson

Vice President

Attachments: A. Résumés

B. Hourly Rate Schedule

C. Standard Terms and Conditions

James D. Simpson
Vice President

Mr. Simpson is a senior executive with more than 28 years of experience in the energy industry. He has held positions at a natural gas utility; an entrepreneurial company providing a proprietary service to generating companies; and state regulatory agencies. His responsibilities have included pricing strategy, regulatory affairs, analysis and planning and business development.

REPRESENTATIVE PROJECT EXPERIENCE

Regulatory Affairs

Representative engagements and responsibilities include:

- Prepared strategic assessment of PBR options for South Central utility
- Prepared validation of sales forecast and analysis of declining use per customer for Northeast utility
- Prepared rate design for Mid Atlantic utility for rate increase filing
- Prepared rate design for Northeast utility for rate increase filing
- Prepared marginal cost study and testimony for Northeast utility
- Prepared Marginal Cost Study and rate design for Northeast utility
- Preparing an assessment of forecast methodology and forecast accuracy for Northeast utility
- Served as primary rate design witness for Bay State Gas Company, Northern Utilities (Maine and New Hampshire) and Granite State Gas Transmission on issues including rate reclassification, restructuring, market competitiveness, and earnings stability

Business Strategy and Operations

Representative engagements and responsibilities include:

- Held position of Chief Operating Officer for a major New England gas company, responsible for all regulated business activities including Gas Supply, Operations, Engineering, Marketing and Sales, and Planning.
- Developed marketing plan and developed and implemented sales strategies.
- Developed brand awareness strategy; created coordinated electronic and physical marketing materials; created and implemented a trade publication strategy. Simplified and shortened sales process; focused on prospective client decision making and understanding of company value proposition.
- Implemented new Optimal Growth strategy to identify opportunities and track investments.
- Led team that created plan to align company structure and culture with new competition-based growth and customer-focus strategy. Led organization during implementation of new strategy, structure, and culture.

Contract Negotiations

Representative engagements and responsibilities include:

- Successfully negotiated contract for first new North America operations site in four years
- Persuaded state regulators to reverse established regulatory policies in conflict with company strategy

- Successfully negotiated unique contract with largest customer on company's system, reversing ten years of unproductive discussions
- Directed negotiation of groundbreaking labor contract that allowed company to use outside contractors and to reduce the union work force by 10%
- Negotiated agreement with pipeline for short term incremental capacity at significant savings
- Negotiated company's commitment to conduct residential customer choice pilot program that provided stakeholders with residential unbundling experience
- Successfully argued for changes to regulators' rate design policies, to improve growth opportunities and customer understanding of pricing. Changes resulted in improved growth rate and customer satisfaction

PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2005 – Present)
Vice President
Assistant Vice President
Executive Advisor

Separation Technologies, Inc. (2001 – 2004)
Vice President, Business Development

Bay State Gas Company (1982 – 2000)
Senior Vice President, Large Customer Sales and Regulatory Affairs (1999 – 2000)
Senior Vice President/COO of Regulated Utility Business (1996 – 1999)
Vice President, Market Analysis and Pricing (1993 – 1996)
Director/Manager of Rates (1982 – 1993)

Massachusetts Department of Public Utilities (1978 – 1982)
Director, Rates and Research Division
Senior Analyst

Wisconsin Public Service Commission (1977 – 1978)
Senior Analyst

EDUCATION

M.S., Economics, University of Wisconsin
B.A., Economics, University of Minnesota, magna cum laude

David A. Heintz
Assistant Vice President

Mr. Heintz is an Assistant Vice President who has over 20-years of experience working with regulated rates and tariffs at both the federal and state levels. He also provides clients with analyses of natural gas projects, markets and issues. Mr. Heintz's areas of expertise include cost of service, allocation and rate design, tariff terms and conditions, rate case preparation and regulatory issues.

RELEVANT PROJECT EXPERIENCE

Regulatory Analysis, Ratemaking, Cost of Service

- Prepared a cost of service study for Puget Sound Energy and assisted in the development of a revenue decoupling mechanism.
- Prepared cost of service studies for Peoples Gas Light and Coke Company and North Shore Gas Company. Assisted in the development of a revenue decoupling mechanism for these companies.
- Performed a cost of service study for Arkansas Oklahoma Gas Corporation. Provided testimony on cost of service and rate design.
- Participated in the development of the revenue requirements for the gas and electric operating companies of a major mid-west utility.
- Participated in a review of the cost of service and rate design methodologies for the natural gas transmission affiliate of a Canadian Crown Corporation.
- Performed an electric cost of service and rate review for the City of Vero Beach, Florida.
- Performed a cost of service study for Chesapeake Utility Corporation, Delaware Division, and provided testimony on rate design issues.
- Performed cost of service and rate design studies integrating the rates and tariffs of Providence Gas Company and Valley Gas Company. Provide testimony on cost of service and proposed new rate designs for the integrated company.
- Performed cost of service study for an investor owned Canadian electric utility.
- Reviewed and provided support for the deferred purchased gas balances of a Louisiana local distribution company.
- Provided support and cost of service analysis for a Pennsylvania electric utility in a FERC complaint case.
- Assisted a Canadian marketing company in its intervention in Northern Border Pipeline Company FERC rate proceeding. Filed testimony on various cost-of-service and rate design issues.
- Assisted an Indiana local distribution company in the preparation of a general rate case and unbundling filing. Assisted in the development of the proposed unbundled services and tariffs.
- Assisted a New Jersey local distribution company with its initial filing under New Jersey's Electric Discount and Energy Competition Act.
- Assisted a major Southwest utility in the preparation of a cost of service and rate design study for filing with the regulatory commission.

- Reviewed and evaluated an electric cost-of-service and unbundling model for the Ontario Energy Board. This model is to be used by the municipal electric utilities in their filings to the Board.
- Assisted a group of Midwest local distribution companies served by Northern Natural Gas Company in a FERC rate proceeding. Filed testimony on various cost-of-service and rate design issues.
- Reviewed the rate harmonization proposal of a major Canadian gas utility for potential shortcomings alternative approaches.
- Responsible for the development, defense, implementation and administration of the Boston Gas Company's rates in rate cases and CGA filings. Prepared annual sales, revenue, margin and gas cost forecasts for budgeting and financial reporting. Directed the company's load research project. Represented the company in regulatory proceedings.
- Responsible for all aspects of United Gas Pipeline Company's rate department, including cost-of-service allocation and rate design, certificates and analysis of other pipeline FERC filings. Represented the company and supported its positions through testimony and negotiations with regulatory agencies, customers and intervenors.
- Responsible for the development of cost-of-service, allocation and rate design studies and filings for Consolidated Natural Gas Company. Analyzed supplier rate and certificate filings. Represented the company and supported its position in negotiations with regulatory agencies, customers and intervenors.
- Responsible for the development and support of FERC staff's position on allocation and rate design issues in pipeline rate and certificate filings.

Valuation and Appraisal

- Assisted in the preparation of a report to the FERC on appraised value and insurance recommendations in a certificate proceeding.

Market Analysis

- Assisted the Province of New Brunswick in the preparation of its Stage I document for the establishment of natural gas distribution within the Province.

Expert Witness Testimony Presentation

- Federal Energy Regulatory Commission
- New York State Public Service Commission
- Massachusetts Department of Telecommunications and Energy
- Pennsylvania Public Utility Commission
- New Jersey Board of Public Utilities
- State of Rhode Island and Providence Plantations Public Utility Commission
- Arkansas Public Service Commission

PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2006 – Present)
Assistant Vice President

Navigant Consulting (1998 – 2006)
Managing Consultant

Boston Gas Company (1993 – 1998)
Director, Rates and Analysis

United Gas Pipeline Company (1992 – 1993)
Director, Rates and Regulatory Affairs

Consolidated Natural Gas Company (1985 – 1992)
Manager, Regulatory Projects

Federal Regulatory Energy Commission (1979 – 1985)
Industry Economist, Allocation and Rate Design Branch

EDUCATION

M.B.A., Katz Graduate School of Business, University of Pittsburgh, 1989
B.S., Economics, Behrend College, Pennsylvania State University, 1978

Andrew F. Hickok
Analyst

Mr. Hickok has contributed to projects involving litigation support, rate design, regulatory support and strategy, and market assessment. Mr. Hickok also has extensive experience in database development, analysis of environmental and energy policy, and utilization of geographic information systems. His work often involves researching and synthesizing regulatory issues, performing statistical analysis of customer usage data, conducting due diligence, and contributing to the writing of reports and expert testimony. Mr. Hickok has over three years of experience in consulting for government and corporate clients.

REPRESENTATIVE PROJECT EXPERIENCE

Litigation Support and Expert Testimony

Mr. Hickok's work includes support for expert witness testimony. His work has included:

- Supporting testimony relating to the regulatory approval of a power purchase agreement by performing comparative analysis of industry contracts
- Supporting expert testimony in a gas rate proceeding through researching company financial reports and updating financial models
- Providing research, analytical and support for expert testimony including benchmarking analysis, research of regulatory precedent, and testimony development
- Managing case documents reviewed and relied upon in the development of expert testimony

Rate Design/ Cost of Service

Mr. Hickok has worked on projects related to utility rate design issues. Specifically, he has:

- Analyzed customer usage data to support reclassification of rate classes for an electric utility
- Analyzed customer usage data to support implementation of a gas revenue decoupling mechanism for a gas utility
- Supported development of a cost of service model for a city-owned gas utility
- Conducted research on performance-based ratemaking and applicable precedents
- Conducted research on current and proposed gas revenue decoupling mechanisms

Regulatory Support and Strategy

Mr. Hickok has contributed to projects analyzing regulations affecting the gas and electric utility industries. His work has included:

- Developing cost model and draft report for a consortium of electric utilities to assess various scenarios of constructing new generation resources in Vermont
- Conducting regulatory research for a large electric utility on its plan to meet future generation needs and assisting in writing strategic report
- Researching legislation to identify financial incentives at the state and federal level for development of renewable sources of energy

Prior to joining CEA, Mr. Hickok contributed to the formulation and evaluation of environmental regulatory policy. His work included:

- Quantified cost impact of a proposed Critical Habitat designation on the Minnesota iron mining industry and drafted report chapter for the US Fish and Wildlife Service.
- Contributed to national study for the US Environmental Protection Agency of potential sea level rise scenarios through stakeholder review, land policy analysis, and GIS mapping.
- Contributed to evaluation of water protection programs through implementing survey of federal and state regulatory agencies and reporting findings.
- Analyzed historical performance of US EPA's Superfund Program and developed benchmark metrics to report cost-effectiveness in compliance with federal mandate.

Market Assessment

Market research activities that Mr. Hickok has been involved with include:

- Supporting gas demand market assessment for a West Coast gas supplier
- Analyzing investment trends in renewable energy in the Northeastern U.S. and authoring a findings booklet tailored to client
- Developing preliminary due diligence reports on energy companies to identify target companies for acquisition. Due Diligence included analysis of financial statements and asset portfolios of energy companies and a review of market area growth opportunities and potential market risks.

PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2006 – Present)
Analyst

Industrial Economics, Inc. (2004 – 2006)
Research Analyst

Cetrulo & Capone, LLP (2003 – 2004)
Paralegal

EDUCATION

B.A., Middlebury College, cum laude, 2002

REDACTED

Concentric Energy Advisors, Inc.
Hourly Rate Schedules
2007

TITLE	HOURLY RATES
CHAIRMAN AND CHIEF EXECUTIVE OFFICER	[redacted]
PRESIDENT	
VICE PRESIDENT, EXECUTIVE ADVISOR	
ASSISTANT VICE PRESIDENT	
PROJECT MANAGER	
SENIOR CONSULTANT	
CONSULTANT	
ASSISTANT CONSULTANT	
ANALYST	
PROJECT ASSISTANT	

ATTACHMENT C

CONCENTRIC ENERGY ADVISORS, INC.
STANDARD TERMS AND CONDITIONS

1. *Scope* – Concentric Energy Advisors, Inc. ("CEA") will perform the services set forth in the Letter or Proposal of which these Terms and Conditions (Terms) are a part. The provisions of these Terms shall control in the case of conflict with any provisions of the Letter or Proposal.

2. *Fees and Expenses* – Unless otherwise stated, fees for services by CEA shall be based upon the rates, at the time the work is performed, of the personnel actually involved in the assignment. Report production and printing, reproduction, and telephone charges will be billed to you at CEA's standard charges for such materials for services. Expenses of consultants while on assignment or any other charge incurred or expenditure made on your behalf will be charged at our cost.

3. *Payment* – CEA will submit monthly invoices reflecting actual work performed and expenses incurred. Payment shall be due in U.S. funds 30 days after the date of an invoice. Amounts past due more than 30 days shall bear interest at an annual rate of 12% from the due date until payment is received.

4. *Sales Tax* – You are responsible for paying any local, state or federal sales, use or ad valorem tax that might be assessed on our services.

5. *Independent Contractor* – It is understood and agreed that CEA shall for all purposes be an independent contractor, shall not hold itself out as representing or acting in any manner for you, and shall have no authority to bind you to any contract or in any other manner.

6. *Termination* – These terms shall be subject to the right of either party to terminate at any time upon not less than ten (10) days prior written notice to the other party. Upon termination, you shall pay the full amount due for services rendered and costs and expenses incurred and not paid for up to that time, and the costs of returning consultant personnel to home base and other reasonable costs and expenses incurred in effecting termination and returning documents.

7. *Responsibility Statement* – CEA agrees that the services provided for herein will be performed in accordance with recognized professional consulting standards for similar services and that adequate personnel will be assigned for that purpose. If, during the performance of these services or within six months following completion of the assignment, such services shall prove to be faulty or defective by reason of a failure to meet such standards, CEA agrees that upon prompt written notification from you prior to the expiration of the six month period following the completion of the assignment containing any such fault or defect, such faulty portion of the services shall be redone at no cost to you up to a maximum amount equivalent to the cost of the services rendered under this assignment. The foregoing shall constitute CEA's sole liability with respect to the accuracy or completeness of the work and the activities involved in its preparation. In no event shall CEA, its agents, employees, or others providing materials or performing services in connection with work on this assignment be liable for any direct, consequential or special loss

or damage, whether attributable to breach of contract, tort, including negligence, or otherwise; and except as herein provided, you release, indemnify, and hold CEA, its agents, employees, or others providing materials or performing services in connection with work on this assignment harmless from any and all liability including costs of defense, settlement and reasonable attorney's fees.

8. *Work Product* – Any report or other document prepared pursuant to these Terms shall be for your use only. CEA's prior written consent is required for the use of (or reference to) its report or any other document prepared pursuant to these Terms in connection with a public offering of securities or in connection with any other financing. CEA hereby agrees, however, to the Client's reference to the work product in connection with any proxy relating to a combination between two parties. It is understood and agreed that CEA's use of its proprietary computer software, methodology, procedures or other proprietary information in connection with an assignment shall not give you any rights with respect to such proprietary computer software, methodology, procedures or other proprietary information. CEA may retain and further use the technical content of its work hereunder.

9. *Excused Performance* – CEA shall not be deemed in default of any provision hereof or be liable for any delay, failure in performance, or interruption of service resulting directly or indirectly from acts of God, civil or military authority, civil disturbance, war, strikes or other labor disputes, fires, other catastrophes, or other forces beyond its reasonable control, whether or not such event may be deemed foreseeable.

10. *Related Litigation* – In the event that CEA employees (current or former), subcontractors or agents are compelled to provide testimony, produce documents, or otherwise incur costs or expend time in any legal proceeding related to CEA's work for you, you agree to reimburse CEA at its regular billing rate per hour for its time expended, and for any expenses incurred (at CEA's direct cost).

11. *Notices* – All notices given under or pursuant to the Terms shall be sent by Certified or Registered Mail, Return Receipt Requested, and shall be deemed to have been delivered when physically delivered if to Concentric Energy Advisors, Inc., 293 Boston Post Road West, Suite 500, Marlborough, MA 01752, Attention Mr. John J. Reed, Chairman and Chief Executive Officer, and if to you at the address shown on the Letter or Proposal of which these Terms are a part or such other address as you may designate by written notice to us.

12. *Complete Agreement* – It is understood and agreed that these Terms and the Letter or Proposal of which they are a part embody the complete understanding of the parties and that any and all provisions, negotiations and representations not included herein are hereby abrogated and that these terms cannot be changed, modified or varied except by written instrument signed by both parties. In the event you issue a purchase order or memorandum or other instrument covering the services herein provided, it is hereby specifically agreed and understood that such purchase order, memorandum, or instrument is for your internal purposes only, and any and all terms and conditions contained therein, whether printed or written, shall be of no force or effect unless agreed to in writing by CEA. No waiver by either parties of a breach hereof or default hereunder shall be deemed a waiver by such party of a subsequent breach or default of like or similar nature.

13. *Governing Law* – This Agreement (consisting of the Letter or Proposal and these terms) shall be construed and otherwise governed pursuant to the laws of the Commonwealth of Massachusetts. The attached

Proposal, of which these General Terms and Conditions (terms) form a part, constitutes an agreement of the parties hereto, and supersedes any previous agreement or understanding. It may not be modified except in writing, and only if executed by both parties.

AGREED AND ACCEPTED:

Gary Cohen

CLIENT SIGNATURE

TITLE: Vice President - Regulation + Pricing - Gas Dist.

COMPANY: National Grid

DATE: 11/29/07

CONCENTRIC ENERGY ADVISORS

REDACTED

Privileged and Confidential

January 17, 2008

Mr. Gary Ahern
Vice President, Gas Distribution Pricing
National Grid
1 Metrotech Center
Brooklyn, NY 11201

Dear Gary:

Concentric Energy Advisors, Inc. ("Concentric") welcomes the opportunity to work with National Grid Rhode Island and National Grid New Hampshire ("National Grid RI" and "National Grid NH;" collectively, "the Companies") on proposals that the Companies will be filing with the Rhode Island Public Utilities Commission ("RIPUC") and the New Hampshire Public Utilities Commission ("NHPUC") to decouple the Companies' revenues from customer demand.

As described in detail in this engagement letter, Concentric's responsibilities related to the Companies' decoupling proposals will include: (a) providing advice and recommendations concerning decoupling mechanism alternatives and (b) preparing testimony to be filed with the RIPUC and NHPUC that describes and supports the decoupling proposals.

This engagement letter provides an introduction to Concentric, a detailed scope of work including a budget estimate, and a description of the proposed project team.

I. INTRODUCTION TO CONCENTRIC

Concentric is a management consulting and economic advisory firm focused on the North American energy industry. Based in Marlborough, Massachusetts, Concentric specializes in regulatory and litigation support, energy market and regulatory strategies, market assessments, transaction-related financial advisory services, energy commodity contracting and procurement, economic feasibility studies, and capital market analyses and negotiations.

The firm's consultants have extensive industry experience; they have held executive positions with management consulting firms, utility companies, regulatory agencies, competitive energy suppliers, and investment banks. Concentric consultants have a substantial and successful history of working on a variety of issues for electric, gas and water clients across North America. It is this broad base of experience, combined with rigorous analysis and a highly collaborative approach to working with clients, that enables Concentric to deliver pragmatic strategic insights and implementable business solutions that achieve client objectives.

Concentric consultants have extensive regulatory experience in Rhode Island and New Hampshire and with the issue of decoupling, which are all relevant to this project. We understand the nature of the regulatory review process in these states, and through our experience with decoupling proposals, we understand the importance in the regulatory process of thoroughly developing the underlying support for decoupling mechanisms.

Concentric is located in Marlborough, Massachusetts, a short drive from both the Companies' offices in Waltham, Westborough, and Northborough and the Rhode Island and New Hampshire Commission offices. Because of our central location, we will be able to meet with the Company and Commission staffs on a timely basis and on short notice. Our central location also minimizes travel expenses.

II. PROPOSED SCOPE OF SERVICES

Statement of the Issues and the Companies' Interests: Concentric understands that the Companies require our assistance to design appropriate decoupling mechanisms and to prepare expert testimony in support of the Companies' proposals to implement a decoupling mechanism, which National Grid RI intends to include in a rate increase case that is to be filed with the RIPUC on or about March 1, 2008 and that National Grid NH intends to include in a rate increase case that is to be filed with the NHPUC on February 24, 2008.

A. Phase I – Decoupling Research

In Phase I, Concentric will perform extensive research on decoupling mechanisms that have been recently proposed by US gas LDCs. Concentric will assist the Companies by drawing from this research and from Concentric's extensive rate design background to develop decoupling proposals that best meet the circumstances and needs of the Companies' customers, regulators and shareholders in Rhode Island and New Hampshire. Concentric will also prepare analyses of the Companies' historical patterns of demand to quantify the impacts of customer-driven on delivery quantities, revenues and earnings.

B. Phase II – Prepare Expert Testimony

In Phase II Concentric will prepare and present expert testimony; to describe and support the Companies' proposals to implement a decoupling mechanism.

III. CONCENTRIC PROJECT CONTRIBUTORS

James Simpson will be the primary contributor for this project; he will be assisted in research and analysis efforts by Andrew Hickok. Biographical summaries of the primary team members are included below; full resumes are included in Attachment D.

James D. Simpson, Vice President, is a senior executive with almost 30 years of experience at Concentric Energy Advisors, a natural gas utility, an entrepreneurial company and state regulatory agencies. Since joining Concentric, he has assisted clients in a variety of matters, focusing on rates, rate design, forecasting and other economic and regulatory issues. In prior positions, his responsibilities have included regulatory affairs, rates, forecasting, business development, pricing strategy, regulatory affairs, analysis and planning; as Chief Operating Officer for a major New England gas company, Mr. Simpson was responsible for all regulated business activities including gas supply, operations, engineering, marketing and sales, and planning. Mr. Simpson holds an M.S. in Economics from the University of Wisconsin and a B.A. in Economics from the University of Minnesota.

Andrew Hickok, Assistant Consultant, joined Concentric in 2006. Mr. Hickok has contributed to projects involving litigation support, rate design, regulatory support and strategy, and market assessment. Mr. Hickok also has extensive experience in database development, analysis of environmental and energy policy, and utilization of geographic information systems. His work often involves researching and synthesizing regulatory issues, performing statistical analysis, conducting due diligence, and contributing to the writing of reports and expert testimony. Mr. Hickok has four years of experience in consulting for government and corporate clients. Mr. Hickok holds a B.A. in Geography from Middlebury College.

IV. PROJECT SCHEDULE

Concentric will provide draft testimony for review and comments and final testimony to be filed at the RIPUC and NHPUC according to the following schedule:

	National Grid RI	National Grid NH
First Draft	February 1, 2008	January 25, 2008
Review Meeting	February 6, 2008	
Final Testimony		February 10, 2008
Filing Date	March 3, 2008	February 24, 2008

V. PROJECT BUDGET

Based on the proposed Scope of Services, Concentric will perform Consulting Services for all project tasks for National Grid RI as summarized in Attachment A up to and including preparation of testimony and supporting schedules, for a fee not to exceed [redacted]; and for National Grid NH as summarized in Attachment B up to and including preparation of testimony and supporting schedules, for a fee not to exceed [redacted].

A. <u>Other Pricing Terms</u>

In addition to the "Not to Exceed" Budgets above, Concentric will bill for (1) Consulting services in support of the Companies' regulatory proceedings, (2) tasks that have not been specified in the Proposed Scope of Services, and (3) travel, copying and other office expenses according to the following terms:

<u>Regulatory Proceedings</u>: Because the level of involvement during the regulatory process is difficult to predict, Concentric will bill all efforts subsequent to the preparation of direct expert testimony in support of the Companies' COSS and rate design proposals, e.g. responses to data requests, oral

testimony and preparation for intervenor testimony on a time and materials basis. Concentric's billing rates are provided in Attachment C.

<u>Tasks outside the Scope of Services</u>: Concentric will perform additional tasks not defined in the Proposed Scope of Services section above on a time and materials basis, at the billing rates provided in Attachment C.

<u>Travel, office expenses, etc:</u> Concentric will charge for these expenses at Concentric's cost; as shown in Attachments A and B, we estimate these costs to be an additional [redacted] each for National Grid RI and National Grid NH.

B. Terms and Conditions

Concentric's Standard Terms and Conditions are included in Attachment E.

VI. Summary

Concentric would again like to thank the Companies for the opportunity to assist National Grid in the upcoming rate cases. Should you have any questions or require clarification of any aspect of this proposal, please do not hesitate to contact me at (508) 263-6224.

Very truly yours,

Concentric Energy Advisors, Inc.

James D. Simpson

James D. Simpson

Vice President

AGREED AND ACCEPTED:

Gary Allen
Client Signature

Title: Vice President

Company: National Grid

Date: 1/18/08

National Grid RI Decoupling Project
Concentric Energy Advisors Itemized Project Pricing Cost Assumptions

Task Description	J Simpson, Asst. Vice President	A Hickok	Admin Assistant	Total Hours	Total Dollars
Project Administration	[redacted]	[redacted]	[redacted]	[redacted]	$ [redacted]
Meetings with client	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Ongoing coordination and project communications	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Phase I - Decoupling Strategy	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Task 1 Decoupling Research	[redacted]	[redacted]	[redacted]	[redacted]	$ [redacted]
Review Decoupling mechanisms implemented by US LDCs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Task 2 Declining Demand Analysis	[redacted]	[redacted]	[redacted]	[redacted]	$ [redacted]
Analyze NGrid RI historical demand	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Quanitfy impacts of declining demand	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Phase II - Expert Testimony	[redacted]	[redacted]	[redacted]	[redacted]	$ [redacted]
Write testimony	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Prepare schedules and exhibits	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
TOTAL Hours	[redacted]	[redacted]	[redacted]	[redacted]	$ [redacted]
Hourly Rate	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]
TOTAL $ Consulting Services Estimate for "Not to Exceed" Tasks	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Travel @ cost					$ [redacted]
Phone @ cost					$ [redacted]
Fed Ex and Misc copying and supplies @cost					$ [redacted]
Total Other Direct Costs					$ [redacted]
GRAND TOTAL					$ [redacted]

REDACTED

Docket 3943
TEC-RI 1-23 Attachment B

National Grid NH Decoupling Project
Concentric Energy Advisors Itemized Project Pricing Cost Assumptions

Task Description	J Simpson, Asst. Vice President	A Hickok	Admin Assistant	Total Hours	Total Dollars
Project Administration		[redacted]	[redacted]	[redacted]	$ [redacted]
Meetings with client		[redacted]	[redacted]	[redacted]	[redacted]
Ongoing coordination and project communications		[redacted]	[redacted]	[redacted]	[redacted]
Phase I - Decoupling Strategy		[redacted]	[redacted]	[redacted]	[redacted]
Task 1 Decoupling Research		[redacted]	[redacted]	[redacted]	$ [redacted]
Review Decoupling mechanisms implemented by US LDCs		[redacted]	[redacted]	[redacted]	[redacted]
Task 2 Declining Demand Analysis		[redacted]	[redacted]	[redacted]	$ [redacted]
Analyze NGrid RI historical demand		[redacted]	[redacted]	[redacted]	[redacted]
Quanitfy impacts of declining demand		[redacted]	[redacted]	[redacted]	[redacted]
Phase II - Expert Testimony		[redacted]	[redacted]	[redacted]	$ [redacted]
Write testimony		[redacted]	[redacted]	[redacted]	[redacted]
Prepare schedules and exhibits		[redacted]	[redacted]	[redacted]	[redacted]
TOTAL Hours	[redacted]	[redacted]	[redacted]	[redacted]	$ [redacted]
Hourly Rate	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]
TOTAL $ Consulting Services Estimate for "Not to Exceed" Tasks	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Travel @ cost					$ [redacted]
Phone @ cost					$ [redacted]
Fed Ex and Misc copying and supplies @cost					$ [redacted]
Total Other Direct Costs					$ [redacted]
GRAND TOTAL					$ [redacted]

REDACTED

Docket 3943
TEC-RI 1-23 Attachment B

REDACTED

CONCENTRIC ENERGY ADVISORS

Concentric Energy Advisors, Inc.
Hourly Rate Schedule

(Currently effective as of 1/1/08)

TITLE	HOURLY RATE
CHAIRMAN AND CHIEF EXECUTIVE OFFICER	[redacted]
PRESIDENT	[redacted]
SENIOR VICE PRESIDENT	[redacted]
VICE PRESIDENT, EXECUTIVE ADVISOR	[redacted]
VICE PRESIDENT: PREFERRED CLIENT RATE	[redacted]
ASSISTANT VICE PRESIDENT	[redacted]
PROJECT MANAGER	[redacted]
SENIOR CONSULTANT	[redacted]
CONSULTANT	[redacted]
ASSISTANT CONSULTANT	[redacted]
ANALYST	[redacted]
ASSOCIATE	[redacted]
PROJECT ASSISTANT	[redacted]

James D. Simpson
Vice President

Mr. Simpson is a senior executive with more than 30 years of experience in the energy industry. He has held positions at a natural gas utility; an entrepreneurial company providing a proprietary service to generating companies; and state regulatory agencies. His responsibilities have included pricing strategy, regulatory affairs, analysis and planning and business development.

REPRESENTATIVE PROJECT EXPERIENCE

Regulatory Affairs

Representative engagements and responsibilities include:

- Prepared comments and testified before the Massachusetts Department of Public Utilities on behalf of a consortium of electric and gas distribution companies on issues related to Decoupling Mechanisms.
- Prepared testimony in support of proposals to implement decoupling mechanisms on behalf of two Northeast utilities.
- Prepared strategic assessment of PBR options for South Central utility
- Prepared validation of sales forecast and analysis of declining use per customer for Northeast utility
- Prepared rate design testimony for Mid Northeast for rate increase filing
- Prepared rate design for Mid Atlantic utility for rate increase filing
- Prepared marginal cost study and testimony for Northeast utility
- Prepared Marginal Cost Study and rate design testimony for Northeast utility
- Preparing an assessment of forecast methodology and forecast accuracy for Northeast utility
- Served as primary rate design witness for Bay State Gas Company, Northern Utilities (Maine and New Hampshire) and Granite State Gas Transmission on issues including rate reclassification, restructuring, market competitiveness, and earnings stability

Business Strategy and Operations

Representative engagements and responsibilities include:

- Held position of Chief Operating Officer for a major New England gas company, responsible for all regulated business activities including Gas Supply, Operations, Engineering, Marketing and Sales, and Planning
- Developed marketing plan and developed and implemented sales strategies
- Developed brand awareness strategy; created coordinated electronic and physical marketing materials; created and implemented a trade publication strategy. Simplified and shortened sales process; focused on prospective client decision making and understanding of company value proposition
- Implemented new Optimal Growth strategy to identify opportunities and track investments
- Led team that created plan to align company structure and culture with new competition-based growth and customer-focus strategy. Led organization during implementation of new strategy, structure, and culture

Contract Negotiations

Representative engagements and responsibilities include:

- Successfully negotiated contract for first new North America operations site in four years
- Persuaded state regulators to reverse established regulatory policies in conflict with company strategy
- Successfully negotiated unique contract with largest customer on company's system, reversing ten years of unproductive discussions
- Directed negotiation of groundbreaking labor contract that allowed company to use outside contractors and to reduce the union work force by 10%
- Negotiated agreement with pipeline for short term incremental capacity at significant savings
- Negotiated company's commitment to conduct residential customer choice pilot program that provided stakeholders with residential unbundling experience
- Successfully argued for changes to regulators' rate design policies, to improve growth opportunities and customer understanding of pricing. Changes resulted in improved growth rate and customer satisfaction

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PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2005 – Present)
Vice President
Assistant Vice President
Executive Advisor

Separation Technologies, Inc. (2001 – 2004)
Vice President, Business Development

Bay State Gas Company (1982 – 2000)
Senior Vice President, Large Customer Sales and Regulatory Affairs (1999 – 2000)
Senior Vice President/COO of Regulated Utility Business (1996 – 1999)
Vice President, Market Analysis and Pricing (1993 – 1996)
Director/Manager of Rates (1982 – 1993)

Massachusetts Department of Public Utilities (1978 – 1982)
Director
Senior Analyst

Wisconsin Public Service Commission (1977 – 1978)
Senior Analyst

EDUCATION

M.S., Economics, University of Wisconsin
B.A., Economics, University of Minnesota, magna cum laude

Andrew F. Hickok
Assistant Consultant

Mr. Hickok has contributed to projects involving litigation support, rate design, regulatory support and strategy, and market assessment. Mr. Hickok also has extensive experience in database development, analysis of environmental and energy policy, and utilization of geographic information systems. His work often involves researching and synthesizing regulatory issues, performing statistical analysis of customer usage data, conducting due diligence, and contributing to the writing of reports and expert testimony. Mr. Hickok has over three years of experience in consulting for government and corporate clients.

REPRESENTATIVE PROJECT EXPERIENCE

Litigation Support and Expert Testimony

Mr. Hickok's work includes support for expert witness testimony. His work has included:

- Supporting testimony relating to the regulatory approval of a power purchase agreement by performing comparative analysis of industry contracts
- Supporting expert testimony in a gas rate proceeding through researching company financial reports and updating financial models
- Providing research, analytical and support for expert testimony including benchmarking analysis, research of regulatory precedent, and testimony development
- Managing case documents reviewed and relied upon in the development of expert testimony

Rate Design/ Cost of Service

Mr. Hickok has worked on projects related to utility rate design issues. Specifically, he has:

- Analyzed customer usage data to support reclassification of rate classes for an electric utility
- Analyzed customer usage data to support implementation of a gas revenue decoupling mechanism for a gas utility
- Supported development of a cost of service model for a city-owned gas utility
- Conducted research on performance-based ratemaking and applicable precedents
- Conducted research on current and proposed gas revenue decoupling mechanisms

Regulatory Support and Strategy

Mr. Hickok has contributed to projects analyzing regulations affecting the gas and electric utility industries. His work has included:

- Developing cost model and draft report for a consortium of electric utilities to assess various scenarios of constructing new generation resources in Vermont
- Conducting regulatory research for a large electric utility on its plan to meet future generation needs and assisting in writing strategic report
- Researching legislation to identify financial incentives at the state and federal level for development of renewable sources of energy

Prior to joining Concentric, Mr. Hickok contributed to the formulation and evaluation of environmental regulatory policy. His work included:

- Quantified cost impact of a proposed Critical Habitat designation on the Minnesota iron mining industry and drafted report chapter for the US Fish and Wildlife Service.
- Contributed to national study for the US Environmental Protection Agency of potential sea level rise scenarios through stakeholder review, land policy analysis, and GIS mapping.
- Contributed to evaluation of water protection programs through implementing survey of federal and state regulatory agencies and reporting findings.
- Analyzed historical performance of US EPA's Superfund Program and developed benchmark metrics to report cost-effectiveness in compliance with federal mandate.

Market Assessment
Market research activities that Mr. Hickok has been involved with include:

- Supporting gas demand market assessment for a West Coast gas supplier
- Analyzing investment trends in renewable energy in the Northeastern U.S. and authoring a findings booklet tailored to client
- Developing preliminary due diligence reports on energy companies to identify target companies for acquisition. Due Diligence included analysis of financial statements and asset portfolios of energy companies and a review of market area growth opportunities and potential market risks.

PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2006 – Present)
Assistant Consultant
Analyst

Industrial Economics, Inc. (2004 – 2006)
Research Analyst

Cetrulo & Capone, LLP (2003 – 2004)
Paralegal

EDUCATION

B.A., Middlebury College, cum laude, 2002

REDACTED

ATTACHMENT E

CONCENTRIC ENERGY ADVISORS

CONCENTRIC ENERGY ADVISORS, INC.

STANDARD TERMS AND CONDITIONS

1. *Scope* – Concentric Energy Advisors, Inc. ("Concentric") will perform the services set forth in the Letter of which these Terms and Conditions (Terms) are a part. The provisions of these Terms shall control in the case of conflict with any provisions of the Letter or Proposal.

2. *Fees and Expenses* – Unless otherwise stated, fees for services by Concentric shall be based upon the rates, at the time the work is performed, of the personnel actually involved in the assignment. Report production and printing, reproduction, and telephone charges will be billed to you at Concentric's standard charges for such materials for services. Expenses of consultants while on assignment or any other charge incurred or expenditure made on your behalf will be charged at our cost.

3. *Payment* – Concentric will submit monthly invoices reflecting actual work performed and expenses incurred. Payment shall be due in U.S. funds 30 days after the date of an invoice. Amounts past due more than 30 days shall bear interest at an annual rate of 12% from the due date until payment is received.

4. *Sales Tax* – You are responsible for paying any local, state or federal sales, use or ad valorem tax that might be assessed on our services.

5. *Independent Contractor* – It is understood and agreed that Concentric shall for all purposes be an independent contractor, shall not hold itself out as representing or acting in any manner for you, and shall have no authority to bind you to any contract or in any other manner.

6. *Termination* – These terms shall be subject to the right of either party to terminate at any time upon not less than ten (10) days prior written notice to the other party. Upon termination, you shall pay the full amount due for services rendered and costs and expenses incurred and not paid for up to that time, and the costs of returning consultant personnel to home base and other reasonable costs and expenses incurred in effecting termination and returning documents.

7. *Responsibility Statement* – Concentric agrees that the services provided for herein will be performed in accordance with recognized professional consulting standards for similar services and that adequate personnel will be assigned for that purpose. If, during the performance of these services or within six months following completion of the assignment, such services shall prove to be faulty or defective by reason of a failure to meet such standards, Concentric agrees that upon prompt written notification from you prior to the expiration of the six month period following the completion of the assignment containing any such fault or defect, such faulty portion of the services shall be redone at no cost to you up to a maximum amount equivalent to the cost of the services rendered under this assignment. The foregoing shall constitute Concentric's sole liability with respect to the accuracy or completeness of the work and the activities involved in its preparation. In no event shall Concentric, its agents, employees, or others providing materials or performing services in connection with work on this assignment be liable for any direct, consequential or special loss or damage, whether attributable to breach of contract, tort, including negligence, or otherwise; and except as herein provided, you release, indemnify, and hold Concentric, its agents, employees, or others providing materials or performing services in connection

REDACTED

with work on this assignment harmless from any and all liability including costs of defense, settlement and reasonable attorney's fees.

8. *Work Product* – Any report or other document prepared pursuant to these Terms shall be for your use only. Concentric's prior written consent is required for the use of (or reference to) its report or any other document prepared pursuant to these Terms in connection with a public offering of securities or in connection with any other financing. Concentric hereby agrees, however, to the Client's reference to the work product in connection with any proxy relating to a combination between two parties. It is understood and agreed that Concentric's use of its proprietary computer software, methodology, procedures or other proprietary information in connection with an assignment shall not give you any rights with respect to such proprietary computer software, methodology, procedures or other proprietary information. Concentric may retain and further use the technical content of its work hereunder.

9. *Excused Performance* – Concentric shall not be deemed in default of any provision hereof or be liable for any delay, failure in performance, or interruption of service resulting directly or indirectly from acts of God, civil or military authority, civil disturbance, war, strikes or other labor disputes, fires, other catastrophes, or other forces beyond its reasonable control, whether or not such event may be deemed foreseeable.

10. *Related Litigation* – In the event that Concentric employees (current or former), subcontractors or agents are compelled to provide testimony, produce documents, or otherwise incur costs or expend time in any legal proceeding related to Concentric's work for you, you agree to reimburse Concentric at its regular billing rate per hour for its time expended, and for any expenses incurred (at Concentric's direct cost).

11. *Notices* – All notices given under or pursuant to the Terms shall be sent by Certified or Registered Mail, Return Receipt Requested, and shall be deemed to have been delivered when physically delivered if to Concentric Energy Advisors, Inc., 293 Boston Post Road West, Suite 500, Marlborough, MA 01752, Attention Mr. John J. Reed, Chairman and Chief Executive Officer, and if to you at the address shown on the Letter or Proposal of which these Terms are a part or such other address as you may designate by written notice to us.

12. *Complete Agreement* – It is understood and agreed that these Terms and the Letter or Proposal of which they are a part embody the complete understanding of the parties and that any and all provisions, negotiations and representations not included herein are hereby abrogated and that these terms cannot be changed, modified or varied except by written instrument signed by both parties. In the event you issue a purchase order or memorandum or other instrument covering the services herein provided, it is hereby specifically agreed and understood that such purchase order, memorandum, or instrument is for your internal purposes only, and any and all terms and conditions contained therein, whether printed or written, shall be of no force or effect unless agreed to in writing by Concentric. No waiver by either parties of a breach hereof or default hereunder shall be deemed a waiver by such party of a subsequent breach or default of like or similar nature.

13. *Governing Law* – This Agreement (consisting of the Letter or Proposal and these terms) shall be construed and otherwise governed pursuant to the laws of the Commonwealth of Massachusetts. The attached Proposal, of which these General terms And Conditions (terms) form a part, constitutes an agreement of

REDACTED

the parties hereto, and supersedes any previous agreement or understanding. It may not be modified except in writing, and only if executed by both parties.

AGREED AND ACCEPTED:

CLIENT SIGNATURE

TITLE: VICE PRESIDENT

COMPANY: NATIONAL GRID

DATE: 1/18/08

Data Request TEC-RI 1-24

Request:

Why was the period October 2007 to January 2008 selected as the basis for determining customers that switched from non-firm to firm service for the proforma adjustment? What would the pro-forma adjustment be if the period Oct – Nov 2007 was used instead, in keeping with the period where actual usage data is available for forecasting the other rate classes (Czekanski Page 8 line 18).

Response:

The period October 2007 to January 2008 was selected because this was the post-test year data that was available at the time the rate case was being prepared and this data allowed the Company to identify known changes subsequent to the test year that were outside the more normal forecasted pattern of customer additions and changes. Excluding the non-firm to firm service conversions that occurred in December 2007 and January 2008 (see Workpaper PCC-4, in Volume 5 at page 196) would change the proforma adjustments as follows:

	Attachment NG-PCC-2 Proforma Adjustment	Revised per description above
Firm Sales (Dth)	236,733	212,255
Firm Transportation (Dth)	1,576,879	1,007,236
Firm Sales	$1,373,414	$1,317,635
Firm Transportation	$1,081,903	$ 719,482

Prepared by or under the supervision of: Peter Czekanski

Data Request TEC-RI 1-25

Request:

For the customers that switched from non-firm to firm service, what usage data provided the basis for the Dekatherm adjustment in Attachment NG-PCC-2 column (e) Page 1 of 2. Please identify both the nature (actual customers who switched or average use of the class) and the time period (i.e., Oct 06-Sep 07).

Response:

Please see Workpaper PCC-4 in Volume 5 at page 196 for the usage data reflected in the Dekatherm adjustment on Attachment NG-PCC-2 column (e) Page 1 of 2 for the customers that switched from non-firm to firm service. The usage is based on each customer's actual gas use plus their historical oil use, converted to equivalent dekatherms of gas use. The time period varied by customer depending on the oil-consumption data provided by the customer but generally was from September 2006 through August 2007.

Prepared by or under the supervision of: Peter Czekanski

Data Request TEC-RI 1-26

Request:

What is the definition of a "customer" for purposes of the revenue per customer target? i.e., is it a premises, a legal entity, a meter, or something else?

Response:

The Company defines a "customer" to be an active meter, which is a meter that has not been shut off.

Prepared by or under the supervision of: James Simpson

Data Request TEC-RI 1-27

Request:

Is the assignment of a meter to a rate class based on that meter's usage or the overall premises usage or something else (and if so please identify)?

Response:

For residential customers the assignment to a rate class is based on whether or not the customer has space heating equipment installed. For small and medium commercial and industrial customers the assignment to rate class is based on total meters usage. For the large and extra large commercial and industrial classes both total usage and load factor (off-peak usage as percent of total usage) are used to determine rate class.

Prepared by or under the supervision of: David Heintz

Data Request TEC-RI 1-28

Request:

What happens to the revenue that the Company receives from new large and extra large rate class customers?

Response:

There will be no difference in the treatment of revenues that the Company receives from new large and extra large rate class customers, compared to revenues received from any other customer except that revenues received from new large and extra large rate class customers will not be included in the calculation of monthly actual billed RPC.[1]

[1] Also, the count of customers that is used in the revenue per customer calculations will not include these new customers.

Data Request TEC-RI 1-29

Request:

How will revenue contributions from the non-firm sales to firm requirements be handled in connection with the Decoupling mechanism?

Response:

The base non-firm margin allowance of $1.6 million is included in the establishment of the proposed revenue requirement by rate class as an off-set to the allocated costs. The customer share of margins above the threshold is incorporated into future DAC and is not part of the decoupling mechanism.

Data Request TEC-RI 1-30

Request:

How was the $1.6 million target revenue from non-firm calculated?

Response:

The $1.6 million target revenue from non-firm is the same level approved in the Company's last rate case, Docket No. 3401.

Prepared by or under the supervision of: Peter Czekanski

Data Request TEC-RI 1-31

Request:

Since returning non-firm customers to Large & Extra Large cause the revenue requirement for those classes to increase, shouldn't the excess revenues from these customers when they move to non-firm also be credited to these same classes?

Response:

The long-standing practice of the Company, as approved by the Commission, has been to allocate the customers share of non-firm margins in excess of the threshold level on a volumetric basis to all firm customers. Allocating the non-firm margin in this fashion is appropriate as the costs of the system are allocated among all firm customers. There are always changes in the number of customers and usage in and between classes between rate cases. There is no rationale for allocating the non-firm margin to specific classes on the assumption that these are the classes the non-firm customers were in or would be in if they were firm.

Data Request TEC-RI 1-32

Request:

Please provide the associated customer counts for columns (b), (e) and (f) of Attachment NG-PCC-2, all rows (rate categories).

Response:

The associated customer counts are as follows:

Description (a)	Actual (Oct 06 - Sep 07) (b)	Adjustment (c)	Normal (d)	Proforma Adjustment (e)	Rate Year - Oct 08-Sep 09 (f)
Average Annual Number of Customers					
Sales Service					
Residential Non-Heating	32,274	0	32,274	-4,559	27,715
Low Income Residential Non-Heating	0		0	2,475	2,475
Residential Heating	191,093	0	191,093	-11,143	179,950
Low Income Residential Heating	0		0	16,000	16,000
Small C&I	18,040	0	18,040	549	18,589
Medium C&I	3,615	0	3,615	95	3,710
Large LLF	225	0	225	-6	219
Large HLF	77	0	77	6	83
Extra Large LLF	6	0	6	1	7
Extra Large HLF	15	0	15	-4	11
Subtotal Firm Sales	245,345	0	245,345	3,414	248,759
Transportation Service					
Medium C&I	778	0	778	29	807
Large LLF	223	0	223	-1	222
Large HLF	78	0	78	2	80
Extra Large LLF	27	0	27	4	31
Extra Large HLF	50	0	50	13	63
Subtotal Firm Transportation	1,156	0	1,156	47	1,203
				3,461	249,962
Miscellaneous Services					
NGV	15	0	15	0	15
Gas Lights	30	0	30	0	30
Manchester St	1	0	1	0	1
Marketers	13	0	13	0	13
Subtotal Miscellaneous	59	0	59	0	59
Total	246,560	0	246,560	3,461	250,021

Prepared by or under the supervision of: Peter Czekanski

Data Request TEC-RI 1-33

Request:

Please provide the billing determinants (including peak day draw) used in the cost of service study. Is the throughput value that of the Rate Year - i.e., column (f) in NG-PCC-2?

Response:

The class usages used in the cost of service study for allocation purposes are those shown on Attachment NG-PCC-2. Note that the Miscellaneous Services were treated as credits to the cost of service and were not included as classes of service in the cost study. These class usages were also used as billing determinants for rate design purposes. The cost of service study did not employ peak day factors for allocation purposes, although a design winter factor was developed for the allocation of LNG and propane function costs.

Customer and Demand billing determinants used in the rate design process can be found on Attachment NG-DAH-4.

Data Request TEC-RI 1-35

Request:

Re: Czekanski testimony page 13 of 24, what happens today if actual uncollectible expenses exceed the 5 year average built into the rate?

Response:

Under the current calculation, the uncollectible ratio (i.e., ratio of uncollectible revenue to total revenue) is fixed based on the 5-year average and the annual recoverable expense is determined by multiplying the uncollectible ratio by the annual GCR revenues. There is no adjustment made to the ratio to reflect actual experience, whether the collections are greater or less than the amount calculated for uncollectible expense.

Prepared by or under the supervision of: Peter Czekanski

Data Request TEC-RI 1-36

Request:

Is the additional adjustment mentioned on lines 18-21 of page 13 of 24 going to be applied to the DAC or to the GCR?

Response:

The additional adjustment for the variance between actual gas-related net write-offs and estimated net write-offs billed through the Company's GCR as mentioned on lines 18-21 of page 13 will be applied to the GCR. A similar type of adjustment for the variance between actual DAC-related net write-offs and estimated net write-offs billed through the Company's DAC will be applied to the DAC as described on page 17 of the testimony at lines 14-17. The value of the GCR and DAC additional adjustments will be calculated separately.

Prepared by or under the supervision of: Peter Czekanski

Data Request TEC-RI 1-37

Request:

Is the Company proposing to use the updated 5 year average each year when calculating the next GCR rate(s)?

Response:

Under the Company's proposal, the updated 5-year average would be used each year to set the GCR rate at the time of the Company's annual GCR filing. On reconciliation, the Company would use the actual uncollectible ratio for the period multiplied times actual GCR revenues to determine the recoverable amount of uncollectible expense for that GCR period.

Prepared by or under the supervision of: Peter Czekanski

Data Request TEC-RI 1-39

Request:

Does the Company include in its calculations of average net write offs the impact of the proposed low income discount rate?

Response:

First, the question assumes that the availability of the low-income discount rate will have a discernible impact on net write-offs, which the Company does not believe will be the case. Second, the average net write offs were based on historical activity and the low-income discount rate was not in existence during this period, although the Company's experience with customers eligible for the low-income rate would have been included in the averages if those customers were on the system during the historical period.

Prepared by or under the supervision of: David Heintz

Data Request TEC-RI 1-40

Request:

Is the annual uncollectible adjustment referred to page 14 of 24 line 16 related to distribution revenue, GCR revenue, or both?

Response:

Under the currently effective tariff, the sum of the per therm DAC components is adjusted to recognize the Company's aggregate uncollectible percentage calculated at the time of the last rate case. The change referenced on page 14 at line 16 is that the uncollectible percentage applied to the DAC will be based on the Company's updated 5-year average. A description of the applicable uncollectible percentage is found on page 17 lines 10 through 17 in the testimony of witness Czekanski.

Prepared by or under the supervision of: Peter Czekanski

Data Request TEC-RI 1-41

Request:

Please provide the list of DAC factors in the current tariff, and the proposed complete list in the proposed tariff.

Response:

The DAC factors, as listed in Section 3, Schedule A, Item 2.0 of the current tariff, are the following:

- System Pressure (SP) factor
- Advanced Gas Technology (AGT) factor
- Low Income Assistance Programs (LIAP) factor
- Environmental Response Cost factor (ERCF)
- On-system margin credits related to non-firm margins
- Reconciliation of the DAC deferred account balance

The proposed tariff in Section 3, Schedule A, Item 2.0 includes the items in the current tariff listed above plus the following:

- Pension and Post-retirement Benefits Other than Pensions (P&PBOP) factor
- Revenue Decoupling Mechanism (RDM) factor
- Capital Expenditures Tracker (CapX) factor
- Service Quality Performance (SQP) factor [NOTE: this is not a new factor since the DAC was designated as the mechanism for crediting any service quality penalties when the service quality measures were established in Docket No. 3476; rather this item is added for clarity]

A marked version of the tariff showing proposed changes can be found in Attachment NG-PCC-4 to the testimony of Peter Czekanski.

Prepared by or under the supervision of: Peter Czekanski

Data Request TEC-RI 1-42

Request:

The proposed tariff (Attachment NG-PCC-5) includes a Low Income Assistance Factor in the DAC with embedded funding in the amount of $1,785,000. How was this figure calculated? In particular, the Mr. Czekanski's testimony and Mr. Stavropoulous' testimony refer to 16,000 heating customers and 2,500 non-heating customers expected to participate. Is the $1,785,000 based on these levels of subscription to the low income distribution rate?

Response:

The embedded funding for the Low Income Assistance Program (LIAP) of $1,758,000 reflects funding of $1,585,000 available for the supplemental LIHEAP low income assistance and $200,000 available for low-income weatherization. These levels of funding are independent of the number of low-income heating and non-heating customers and are the same as made available to low-income customers in the Company's last rate case, Docket No. 3401.

Data Request TEC-RI 1-43

Request:

In the marked up tariff, Attachment NG-PCC-4, Section 3, Schedule A, Sheet 4, under 3.3 LIAP Factor, a figure of $1,793,901 was deleted. What did this amount represent? How was this money distributed to low income customers? How was this funded? How were the costs allocated to rate classes? Is this program being eliminated? Is it correct to conclude that ratepayers are essentially providing the same level of funding for low income discounts going forward as they have in the past, since $1,785,000 is within 1% of $1,793,901?

Response:

The figure of $1,793,901 included $1,585,000 of funds available to supplement federal LIHEAP grants provided to qualified low income customers and $200,000 for the low-income weatherization program administered by the State Office of Energy Resources (OER), plus $8,901 of working capital. These low-income programs are proposed to continue, but the Company is not proposing to separately quantify a working capital component. At the start of each winter heating season, the Company coordinates with OER to establish a percentage of the LIHEAP grant that the Company will match in order to disperse the $1,585,000 of supplemental funds. The matching percentage is based on the estimated level of federal LIHEAP funding and the number of gas customers expected to receive the grants. The low-income weatherization program is administered by OER.

Prepared by or under the supervision of: Peter Czekanski

Data Request TEC-RI 1-44

Request:

Concerning Decoupling: The fact that therms per customer are declining will translate into lower system costs over time. Please show any calculations the Company has done to quantify this effect. Is it expected that these cost savings will accrue in any cost item that is a function of demand or throughput?

Response:

The fact that therms per customer are declining will not result in lower system costs over time. Under certain circumstances, extended periods of declining use per customer may reduce the rate at which system costs and annual revenue requirements would increase. The Company's costs to provide distribution service are affected by a complex set of factors including overall inflation, utility-specific inflation, the age and condition of the distribution system, the materials used in the distribution mains, leak experience, number and classifications of customers, and rate of system expansion. Except for system reinforcement, these factors are not affected by declining use per customer. The Company has not prepared any calculations to quantify this possible result, nor would it be reasonably possible to do so.

Prepared by or under the supervision of: James Simpson

Data Request TEC-RI 1-45

Request:

What is the estimated average square footage of the properties being targeted for the Gas Marketing Program broken down by class? What is the average square footage for all customers by class for the properties currently being served in (1) the Residential Heating class and (2) the small C&I class?

Response:

The Company does not target buildings by size through the proposed Gas Marketing Program. Rather, the Company targets property owners on the basis of whether their building is (1) residential, commercial or industrial, and (2) whether the property is located on the Company's distribution system. In any event, Company billing records do not include data on physical parameters of customer premises such as floor area. As a result, the data requested is not available by rate class. However, the Company does purchase building data from outside services for use in future parametric studies and has recently done so for Rhode Island.

For residential buildings the following statistics are derived from the purchased data:

Floor Area (square feet)	
Mean:	1,726
Std. Deviation:	851
Minimum:	13
Maximum:	28,105

For commercial buildings, the purchased data does not include the actual area. Rather, the data groups business locations into four estimated floor area categories. Commercial businesses are distributed as follows:

Floor Area (square feet)	
0 - 2,499	36.5%
10,000 - 39,999	17.6%
2,500 - 9,999	41.6%
40,000+	4.3%

Prepared by or under the supervision of: Sean Mongan

Data Request TEC-RI 1-46

Request:

Will it be a requirement that customers participating in the Gas Marketing Program install the most energy efficient heating equipment?

Response:

It will not be a requirement that customers participating in the Gas Marketing Program install the most energy efficient heating equipment. The program communications will promote high efficiency equipment but the Company recognizes that some customers may be unable to install HE equipment for technical and/or economic reasons.

Data Request TEC-RI 1-47

Request:

New space heating equipment installations will be more efficient than the average efficiency of equipment in the existing Residential Heating class. Please show the two figures, and the resulting annual average usages for the two groups. Then please show the impact on rates for the existing customers under a decoupling mechanism when the Gas Marketing customers are added to their class, providing their revenue contributions, and adding to the customer count.

Response:

The Gas Marketing Program targets customers or prospects that currently do not heat with natural gas. It does not target customers or prospects that already use natural gas and are reducing their usage through the installation of new, more efficient gas equipment, which is the focus of the Company's decoupling proposal. In this proceeding, the Company's projections for added load resulting from the Gas Marketing Program are factored into the proposed rates (assuming the use of energy efficient equipment) and any decoupling impact analysis provided in various responses to data requests.

In terms of the efficiency gains between heating oil and natural gas, it is possible to estimate from published data that typical oil-heat exchanger fouling results in a loss of efficiency of about 2% points per year, up to about a 10% loss. Oil-fired furnaces that where purchased at the then current efficiency standards (assuming today's typical annual fuel consumption and that the equipment was properly maintained), would perform as follows.

15 years old	71%	Using 609 gallons of No. 2 oil
30 years old	64%.	Using 676 gallons of No. 2 Oil

By comparison, new minimally compliant gas-fired furnaces are typically rated at an efficiency of 81% and are expected to use nominally 73.7 DTH annually, which is equivalent to 534 gallons of No. 2 Oil. The new Energy Star gas furnace, which would qualify for a rebate under the Company's energy efficiency program, would have an efficiency of at least 92% and use 65 DTH in a normal year, which is equivalent to 471 gallons of No. 2 oil.

Prepared by or under the supervision of: Sean Mongan

Data Request TEC-RI 1-48

Request:

With respect to decoupling, do the monthly revenue targets factor in the effect of budget billing customers? Please describe.

Response:

Budget billing customers are factored into the monthly revenue targets on the basis of actual metered gas use and the revenues from actual metered gas use, not on the basis of the monthly budget billing amounts. This is the same basis that they are reflected in the actual test year monthly billing determinants.

Prepared by or under the supervision of: Peter Czekanski

Data Request TEC-RI-1-49

Request:

Please provide documentation for the assertion that underpins the Decoupling mechanism, namely that it is the number of customers that drives the Company's costs to provide distribution service? Please provide your response for each customer class.

Response:

RPC decoupling mechanisms are not predicated on the concept that the number of customers drives a utility's costs to provide distribution service. Rather, RPC decoupling mechanisms are designed to ensure that a gas utility receives revenues that are consistent with the revenue requirement ordered by regulators in the utility's most recent rate case.

Traditional ratemaking, which is based on an examination of historical utility costs and billing determinants, is designed to allow regulated utilities to earn a fair rate of return if the conditions that affect utility revenues and costs are generally similar and consistent between the historical test year period and the future periods when the rates that are determined from the test year data will be charged. Traditional ratemaking may not produce reasonable results when the conditions that affect utility costs and revenues in the years that the rate case rates will be charged are very different from the conditions that were experienced during the test year.

Decoupling measures are an increasingly common category of revenue-related modifications to traditional ratemaking. Decoupling measures address revenue-related shortcomings in traditional ratemaking. Specifically, as a result of conservation and other demand response efforts, the conditions that will impact utility revenues in the future when a specific set of base rates will be charged are very likely to be different from the conditions that were experienced during the test year that was used to determine that set of base rates.

There are two different aspects to the way that an RPC decoupling mechanism works to provide a utility with revenues that are consistent with the results of the utility's most recent rate case: (1) revenues for existing customers and (2) revenues for new customers.

Existing customers: Decoupling mechanisms act to ensure that the revenues that are collected from existing customers[1], by class and as a group, remain at the level that was set by regulatory order in the most recent rate proceeding[2].

[1] In the context of a decoupling mechanism, "existing customer" is a customer whose billing determinants are included in billing determinants and in Target RPC.

[2] Decoupling mechanisms do not protect against reductions in customers; the utility is at risk for declining revenues due to declining customers in any class.

New customers: Decoupling mechanisms act to provide incremental revenues for each new customer at the class-specific Target RPC. Although the target RPC is not likely to fully reflect the incremental costs[3] to connect a new customer and to provide service in the first years that the new customer is connected[4], providing incremental revenues for each new customer at the class-specific Target RPC is a reasonable approach, as has been implicitly or explicitly recognized in the approval of the RPC decoupling mechanisms that have been implemented throughout the country.

3 Typical incremental costs include cost of installing a meter, riser, and service, and expenses associated with customer billing processes.

4 The costs to provide service to a customer, adjusted for inflation, declines over time as the net book value of the plant that is directly associated with that customer (meter, service) declines due to the increasing accumulated depreciation.

Data Request TEC-RI 1-52

Request:

What happens, according to the Company's proposed rate regime in this filing, if the added revenues from new customers result in National Grid earning more revenue than it needs to operate and maintain the system?

Response:

Assuming that the "added revenues referred to in this request relate to the Company's decoupling proposal and the average revenue per customer approach proposed therein, the Company would be allowed to retain new customer revenue equal to that customer's class average revenue per customer.

As stated in the Company's response to Data Request TEC-RI 1-49, "[d]ecoupling mechanisms act to provide incremental revenues for each new customer at the class-specific Target RPC. Although the target RPC is not likely to fully reflect the incremental costs[1] to connect a new customer and to provide service in the first years that the new customer is connected[2], providing incremental revenues for each new customer at the class-specific Target RPC is a reasonable approach, as has been implicitly or explicitly recognized in the approval of the RPC decoupling mechanisms that have been implemented throughout the country."

It should also be noted that, to the extent that revenues from new customers (equal to the class average revenue per customer) exceed the revenue needed to operate and maintain the system, and contributes to Company earnings in excess of its allowed return on equity, the excess return would be subject to the Earnings Sharing Mechanism.

1 Typical incremental costs include cost of installing a meter, riser, and service, and expenses associated with customer billing processes.

2 The costs to provide service to a customer, adjusted for inflation, declines over time as the net book value of the plant that is directly associated with that customer (meter, service) declines due to the increasing accumulated depreciation.

Prepared by or under the supervision of: Mike Laflamme

Data Request TEC-RI 1-53

Request:

Since the Company is protected against earning less than its allowed rate of return because its revenues are guaranteed, why should the Company share any margins that are above its allowed rate of return?

Response:

The Company strongly disagrees with the premise of the request that the Company is "protected against earning less than its allowed rate of return because its revenues are guaranteed." The decoupling mechanism operates as a revenue recovery mechanism, not a cost recovery mechanism, and therefore, cost increases that are not mitigated or controlled by the Company will have the effect of causing a degradation of earnings. Specifically, the decoupling mechanism operates to provide the Company with the amount of revenue equal to the number of customers in each class times the class average revenue per customer determined in the rate case so that losses in customer usage after rates are set do not have the effect of eroding the Company's ability to recover its allowed revenues (all else being equal). The Company remains at risk for revenues associated with customers leaving the system after rates are set. More importantly, the Company is at risk for operating its business at the underlying expense levels included in its cost of service used to establish delivery rates.

Prepared by or under the supervision of: Mike Laflamme

Data Request TEC-RI 1-54

Request:

Please show, for each rate class the share of revenue being received from each of the three major revenue categories of Customer, Variable, and Demand.

Response:

Please see Attachment NG-PCC-3 to the testimony of Mr. Czekanski.

Prepared by or under the supervision of: Peter Czekanski

Data Request TEC-RI 1-55

Request:

The Cost of Service and rate design identifies the need to collect more revenue from the fixed portions of the rate. Given that, explain the rationale for collecting the decoupling variance using a per dekatherm charge.

Response:

As explained in the response to Data Request DIV-7-14(b):

> There is no inconsistency between the Company's rate design goal of recovering a higher proportion of base rate revenues through fixed charges and implementing an RPC component of the DAC that is on a cents per therm basis. As explained in the response to DIV-7-1, increasing fixed charges addresses two objectives, (1) revenue decoupling and (2) setting rates on the basis of costs; the RPC mechanism addresses one of these two objectives, revenue decoupling.

Prepared by or under the supervision of: James Simpson

Data Request TEC-RI 1-56

Request:

What is the definition of a "Customer" for purposes of the Revenue Decoupling Mechanism?

Response:

Please see the Company's responses to Data Requests TEC-RI-1-16 and TEC-RI-1-26.

Prepared by or under the supervision of: James Simpson

Data Request TEC-RI 1-57

Request:

For the purpose of better understanding the decoupling proposal, please show the bill impacts under the following scenario: Customer A uses 500,000 dekatherms per year. Customer A is in a rate class with 49 other customers where the total usage (including Customer A's) is 2,500,000 dekatherms. Because gas is a major component of their operating costs, Customer A has double the energy efficiency level of the average customer in its industry, and thus has no opportunity to participate in the current Company DSM program this year. The DSM charge is 15 cents a dekatherm. Customer A adds capacity to its facility and as a result increases its gas usage by 20%. As a result of other customers participating in the DSM program, as well as a mild winter, usage for the class as a whole declines 5%. Please show the bill impacts to customer A as a result of the DSM program plus decoupling, using the proposed Extra Large High Load Factor rates and revenue per customer target.

Response:

The Company cannot provide a response to this request because (1) there is not sufficient information included in the question concerning Customer A and the other 49 customers to calculate monthly or annual revenues based on the proposed Extra Large High Load Factor rates[1]; and (2) it would be inappropriate and misleading to compare actual billed RPC from this hypothetical class of 50 customers to the Target RPC of the actual Extra Large High Load Factor class.

[1] In addition to a Customer Charge per month, and a distribution charge per therm, Extra Large High Load Factor customers are billed a Demand Charge per therm of Maximum Average Daily Quantity, which is determined with historical billing data from the most recent November April period.

Data Request TEC-RI 1-58

Request:

Repeat question 57 using the customer with the highest usage in the National Grid RI gas system, and the actual usages and customer counts in that rate class.

Response:

Please see the response to Data Request TEC-RI 1-57.

Prepared by or under the supervision of: Peter Czekanski

Data Request TEC-RI 1-59

Request:

Now suppose that same customer, the largest customer that National Grid serves in RI, leaves RI and the system. Please calculate the resulting impact on the customers that remain in that class.

Response:

Please see the response to data request TEC-RI 1-57.

Prepared by or under the supervision of: Peter Czekanski

Data Request TEC-RI 1-62

Request:

How will the capital tracker be calculated?

Response:

It is important to note that there are two separate and distinct capital tracker alternatives proposed in this filing. The first capital tracker alternative would be used as the mechanism to refund or collect the revenue requirement associated with the proposed Accelerated Replacement Program ("ARP"). The second alternative is the full capital tracker proposed in the alternative three-year Rate Plan. The ARP and Rate Plan capital tracker operate very differently.

The ARP would provide for a customer credit for the first rate year period equal to the revenue requirement of the amount of actual ARP spend that is less than the ARP spend amount include in the Rate Year cost of service. If the Company spends more than the targeted ARP spend in the Rate Year, no incremental rate adjustment would result. For years after the Rate Year the Company would be allowed a rate adjustment for the revenue requirement of actual ARP spend up to the targeted level of annual ARP spend included in this proceeding. Please refer to the testimony of Mr. Laflamme, beginning on Page 52 of 60, for a discussion of the ARP targets by fiscal year and see Attachment NG-MDL-5, page 1 of 2 for an illustrative calculation of the ARP revenue requirement calculation.

The three year Rate Plan full capital tracker is intended to be a customer protection mechanism and can result only in a customer credit. The full capital tracker would replace the need for the ARP tracker and would reconcile actual total capital expenditures to the forecasted capital expenditures included in the Company's underlying annual costs of service for each of the years in the three-year Rate Plan period. The credit would be equal to the revenue requirement of the annual amount of actual total capital expenditures that is less than the forecasted total annual capital expenditures included in the Rate Plan. This reconciliation would ensure that during the three-year Rate Plan period customers are supporting only those forecasted capital expenditures that materialize. Lastly, if the Rate Plan is approved and the resulting rates for the final year of the Rate Plan continue beyond the three-year Rate Plan period, this full capital tracker would be suspended and replaced with the ARP for ensuing years. Please refer to the testimony of Mr. Laflamme, beginning on Page 59 of 60, for a further discussion of the full capital tracker proposal and see Attachment NG-MDL-5, page 2 of 2 for an illustrative calculation of the full capital tracker revenue requirement calculation.

Prepared by or under the supervision of: Mike Laflamme

Data Request TEC-RI 1-63

Request:

Explain why the capital tracker should be recovered using a per dekatherm volumetric charge? Reconcile your answer to the treatment of mains and services in the cost of service study submitted in this filing?

Response:

The proposed capital tracker would recover/credit to customers the revenue requirement impact associated with differences between actual capital expenditures and those included in the rate case revenue requirement. Although this approach may not be an exact match with how the investments were allocated in the cost study, it provides a mechanism for recognizing differences in actual capital spending without performing a full cost study.

Prepared by or under the supervision of: David Heintz

TEC-RI Data Request 1-64

Request:

Please add a hypothetical $5 million addition to capital expenditures. Show the impact on revenues and average bills by class using the CapX tracker factor to pay for the $5 million. Next, flow that $5 million through the cost of service and show the resulting impact on revenues and average bills by class.

Response:

The three year CapX tracker is intended to be a customer protection mechanism and can result only in a customer credit. Attachment NG-MDL-5, page 2 shows that the annual revenue requirement of a $5 million decrease in capital expense is $882,364. Assuming the volume level filed for in the rate case this equates to a $0.0245/dekatherm unit rate impact. The impact of the CapX tracker to class revenue requirement and average annual bills is shown in columns (C) and (D) below.

The class cost of service study allocated mains cost using the RSUM factor. Assuming all of the difference in investment is in mains the impact on class revenue requirement and average annual bills is shown in columns (F) and (G) below.

		DAC Recovery		Allocated Cost Study Recovery		
Rate Class	Volumes	Revenue Adjustment	Decrease to Avg. Annual Bill	RSUM Alloc. Factor	Alloc. Cost Study Adj.	Decrease to Avg. Annual Bill
(A)	(B)	(C)	(D)	(E)	(F)	(G)
Residential Non-Heat	524,925	$ (12,842)	$ (4.64)	1.39%	$ (12,302)	$ (4.72)
Residential Non-Heat Discount	46,811	(1,145)	$ (4.64)			$ (4.72)
Residential Heat	16,549,749	(404,891)	$ (22.60)	51.57%	(455,071)	$ (23.31)
Residential Heat Discount	1,462,132	(35,771)	$ (22.60)			$ (23.31)
Small C/I	2,365,191	(57,865)	$ (31.11)	6.97%	(61,476)	$ (32.13)
Medium C/I	5,272,745	(128,998)	$ (268.29)	14.71%	(129,813)	$ (269.59)
Large Low	2,655,646	(64,971)	$ (1,414.68)	7.72%	(68,136)	$ (1,481.14)
Large High	1,034,400	(25,307)	$ (1,431.28)	2.52%	(22,218)	$ (1,254.76)
X-Large Low	1,206,657	(29,521)	$ (7,140.83)	3.43%	(30,278)	$ (7,313.56)
X-Large High	4,947,980	(121,053)	$ (13,920.60)	11.68%	(103,069)	$ (11,835.68)
Total	36,066,235	$ (882,364)			$ (882,364)	

Revenue Impact of $5,000,000	
CapX Adjustment	(882,364)
Unit Rate	$ (0.0245)

Prepared by or under the supervision of: David Heintz

Data Request TEC-RI 1-65

Request:

Re Czekanski testimony page 17 of 24, he proposes in lines 11-14 that the Company's annual DAC filing include an updated calculation of the average net write-offs as a percentage of revenue for the most recent five year period. What will this updated number be used for?

Response:

Under the Company's proposal, the updated 5-year average would be used each year to set the DAC rate at the time of the Company's annual DAC filing. On reconciliation, the Company would use the actual uncollectible ratio for the period multiplied times actual DAC revenues to determine the recoverable amount of uncollectible expense for that DAC period.

Prepared by or under the supervision of: Peter Czekanski

Data Request TEC-RI 1-66

Request:

Re Czekanski testimony page 19 of 24, lines 14-16 state that the proposed cap on non-firm distribution rates will be calculated as fifty percent above the target RPC. Since non-firm rates are not included in the Company's Decoupling proposal, which rate class has been chosen to provide the RPC target? Please show all calculations used to arrive at the figures of $0.4279 per therm and $0.1701 per therm.

Response:

Whereas the Target RPC's for firm service customers are calculated on the basis of revenue per customer, the non-firm margin cap is on the basis of revenue per therm, calculated as follows:

		Large Low Load	Extra Large Low Load
Proposed Base Revenue (Attachment NG-DAH-4)		$ 7,574,960	$ 1,368,226
Forecasted Rate Year Therms		26,556,458	12,066,568
Base revenue per Therm		$ 0.2852	$ 0.1134
Non Firm Margin Cap @ Base Revenue +	50%	$ 0.4279	$ 0.1701

Also, please see the Company's response to Data Request DIV 6-26.

Prepared by or under the supervision of: Peter Czekanski

Data Request TEC-RI 1-67

Request:

The Northeast Gas Association, in testimony before a joint hearing of the RI legislature on energy policy on November 30, 2005, quoted a study undertaken in 2003 by FERC and DOA, “Interruptible contracts are typically less expensive because capacity is only paid for if used, and the supplier or transporter may interrupt service.” Please explain how your proposed non-firm rate that can be as high as 150% of the equivalent firm service rate satisfies the principle articulated here. If not, what justifies the deviation from this principle?

Response:

The Company's understanding of the referenced testimony is that it related to interruptible contracts for capacity on the interstate pipeline system. Regardless, the Company’s proposed non-firm rate is designed to generate margin to the benefit of firm service customers and is based on value-of-service pricing. The value-of-service pricing establishes the monthly rate at a level relative to the customer's alternative fuel subject to a minimum and a maximum or cap. Value-of-service pricing is intended to recognize that firm customers bear the cost of the investment made to construct and maintain the distribution system, where non-firm customers have chosen not to share in that burden. Thus, the value-of-service pricing regimen recognizes that firm customers should receive a benefit for the use of their facilities by entities choosing to avoid that cost burden, while also having the distribution facilities available to them for their non-firm use. Since dual-fuel customers are able to switch between fuels and avoid the costs that firm-service gas customers bear, it makes sense that the cost of using the distribution system on an “at will” basis is tied to the cost of the alternative fuel because this is what ensures that firm customers are receiving a “market price” for the use of their resource assets. Non-firm customers always have the opportunity to avoid a “non-firm rate that can be as high as 150% of the equivalent firm service rate,” by committing to firm service and contributing to the cost of the facilities that they use to meet their gas-supply needs.

Prepared by or under the supervision of: Peter Czekanski

Data Request TEC-RI 1-68

Request:

For the Non-firm tariff proposed by the Company (Czekanski testimony page 19), the proposed cap will be almost 43 cents a therm for under 25,000 therms a month, and approximately 17 cents a therm for under 25,000 therms a month. This suggests an underlying differential in the cost to serve these two classes of over 2 to 1. Please provide the documentation that shows the cost of service for the under 25,000 therm class is over twice as high as the over 25,000 therm class.

Response:

Please see the Company's responses to Data Requests DIV 6-26 and DIV 6-27.

Prepared by or under the supervision of: Peter Czekanski

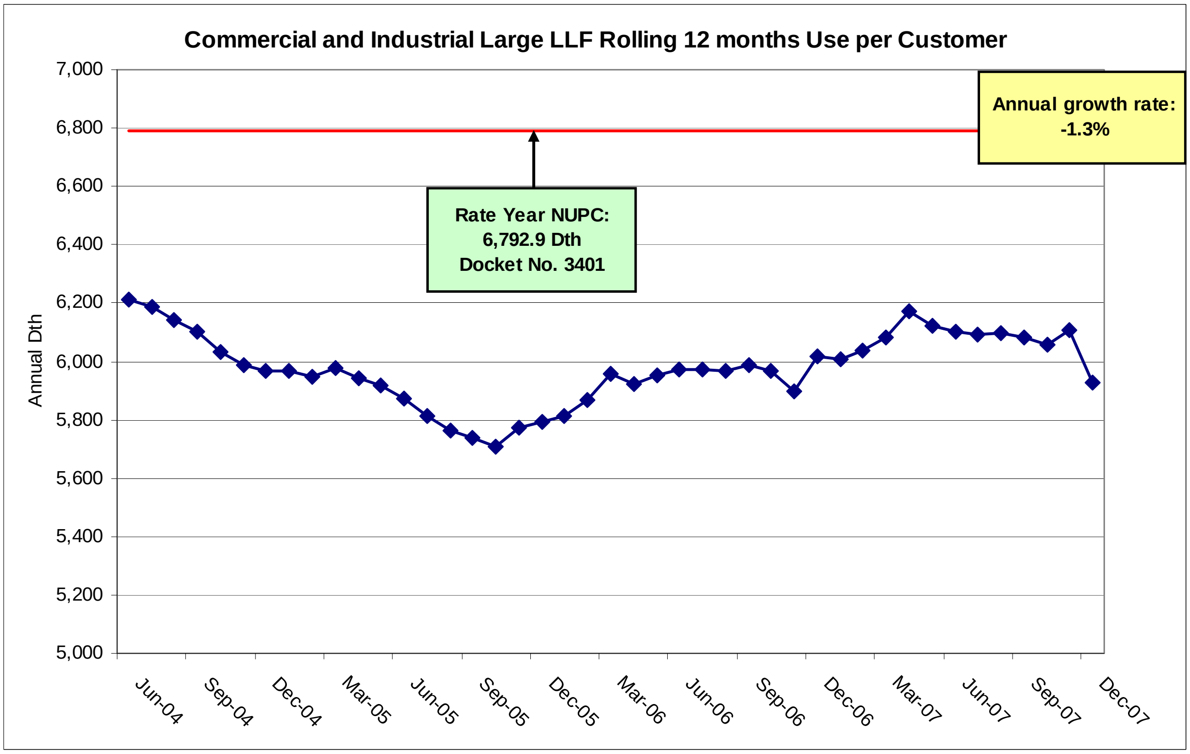
Data Request TEC-RI-1-69

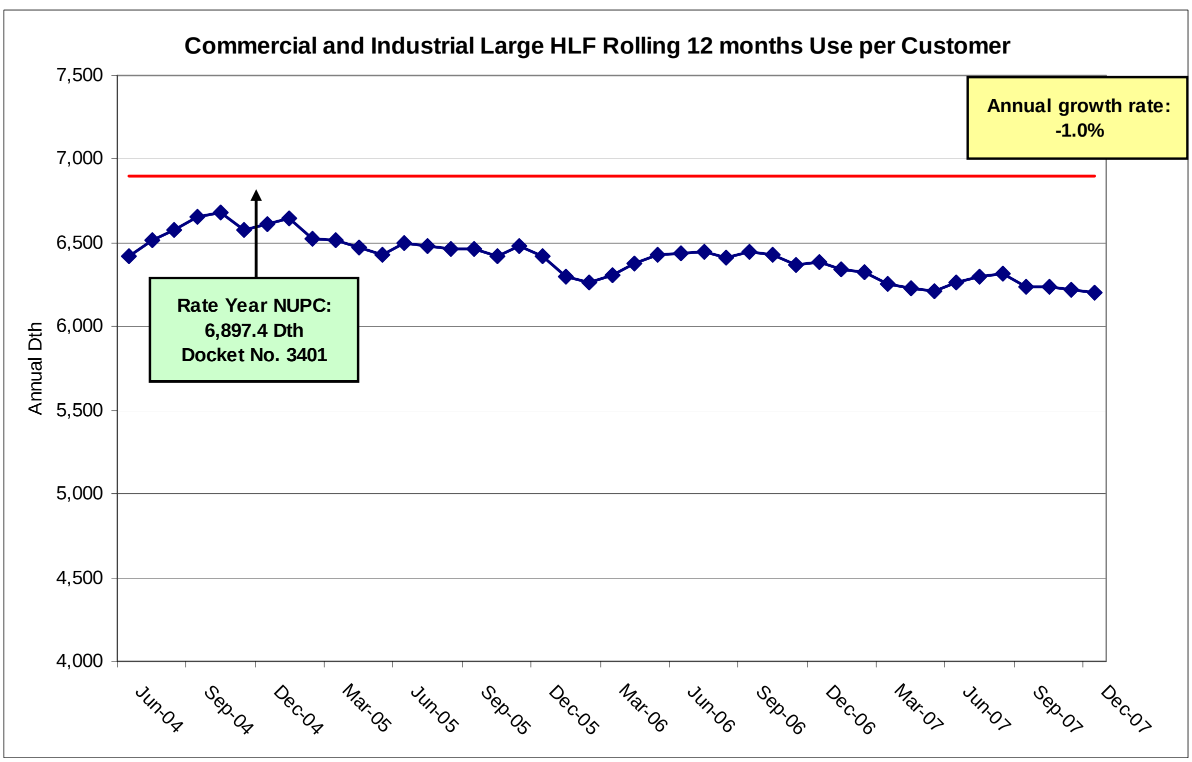
Request:

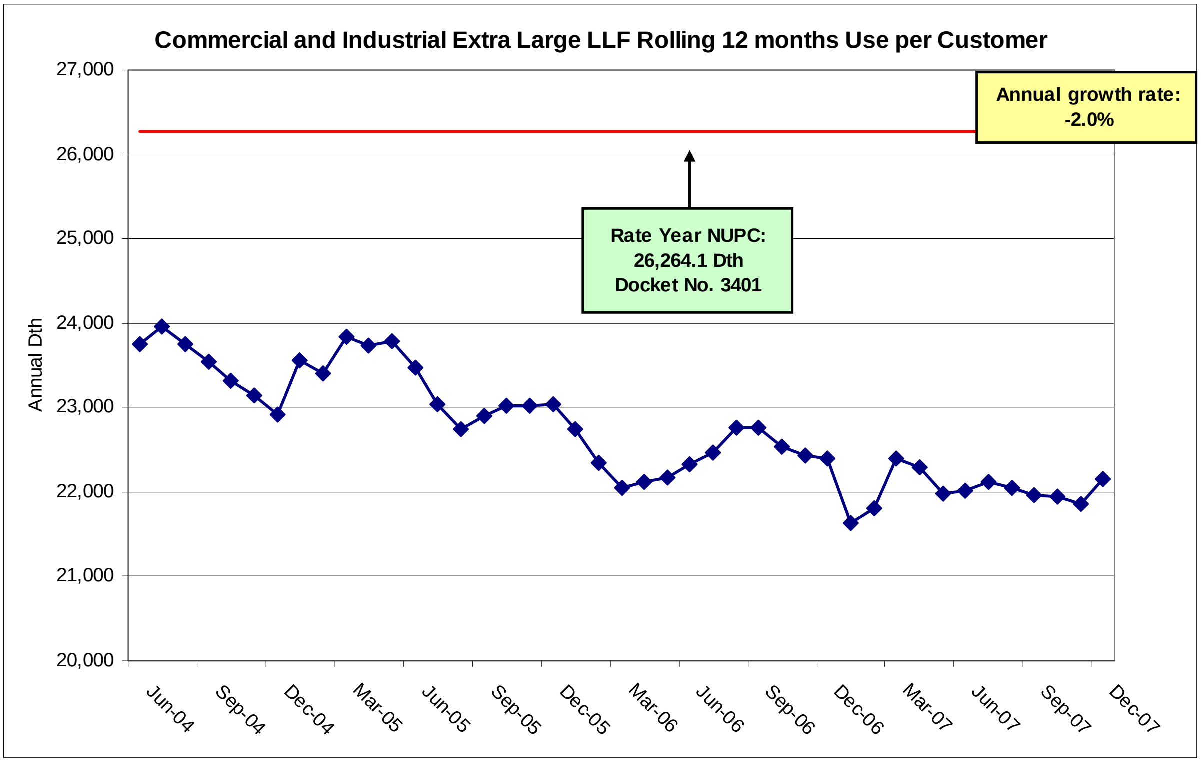
Re attachments NG-JDS-4, 5, & 6 present Rolling 12 month NUPC graphs (June 2004-Dec 2007) for Residential, Commercial & Industrial Small, and C&I Medium. Please show the graph for C&I Large and Extra Large.

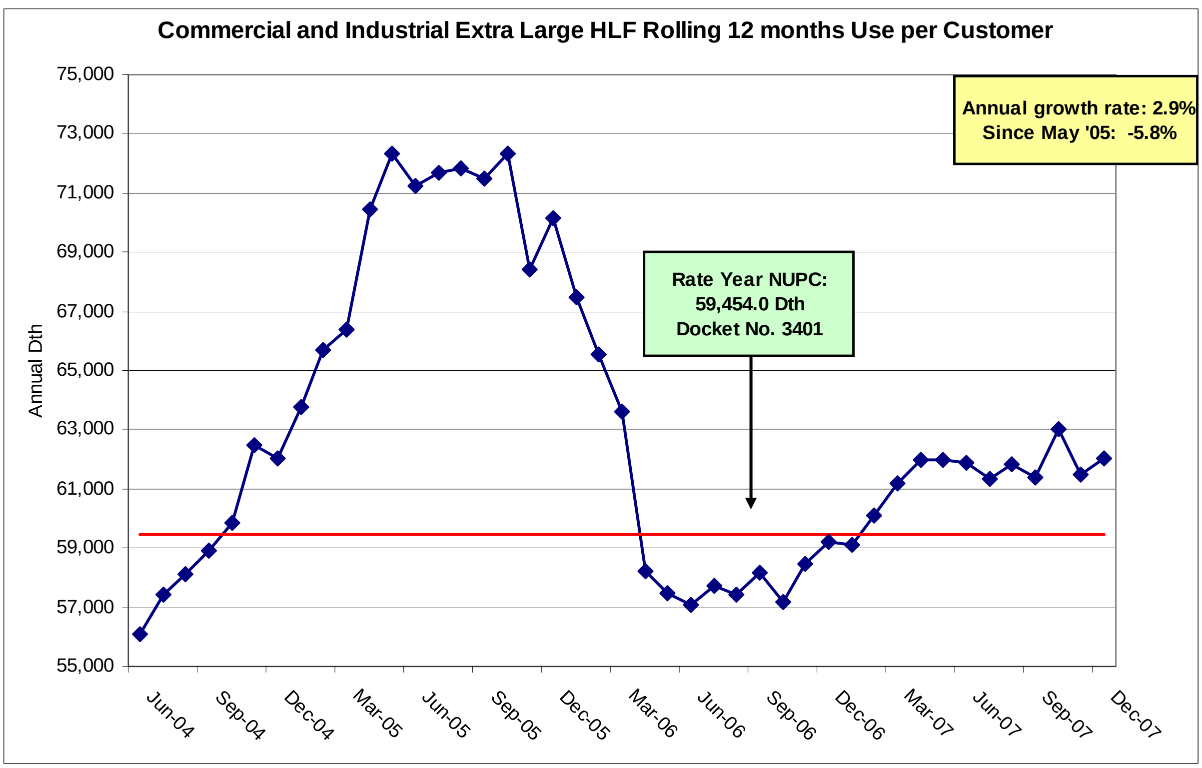
Response:

Please see Attachment TEC-RI-1-69 for the requested graphs.


Commercial and Industrial Large LLF Rolling 12 months Use per Customer
Annual growth rate:
-1.3%
Rate Year NUPC:
6,792.9 Dth
Docket No. 3401
Annual Dth
7,000
6,800
6,600
6,400
6,200
6,000
5,800
5,600
5,400
5,200
5,000
Jun-04
Sep-04
Dec-04
Mar-05
Jun-05
Sep-05
Dec-05
Mar-06
Jun-06
Sep-06
Dec-06
Mar-07
Jun-07
Sep-07
Dec-07


Commercial and Industrial Large HLF Rolling 12 months Use per Customer
Annual growth rate:
-1.0%
Rate Year NUPC:
6,897.4 Dth
Docket No. 3401
Annual Dth
7,500
7,000
6,500
6,000
5,500
5,000
4,500
4,000
Jun-04
Sep-04
Dec-04
Mar-05
Jun-05
Sep-05
Dec-05
Mar-06
Jun-06
Sep-06
Dec-06
Mar-07
Jun-07
Sep-07
Dec-07


Commercial and Industrial Extra Large LLF Rolling 12 months Use per Customer
Annual Dth
27,000
26,000
25,000
24,000
23,000
22,000
21,000
20,000
Annual growth rate: -2.0%
Rate Year NUPC: 26,264.1 Dth Docket No. 3401
Jun-04
Sep-04
Dec-04
Mar-05
Jun-05
Sep-05
Dec-05
Mar-06
Jun-06
Sep-06
Dec-06
Mar-07
Jun-07
Sep-07
Dec-07


Commercial and Industrial Extra Large HLF Rolling 12 months Use per Customer
Annual Dth
75,000
73,000
71,000
69,000
67,000
65,000
63,000
61,000
59,000
57,000
55,000
Annual growth rate: 2.9%
Since May '05: -5.8%
Rate Year NUPC: 59,454.0 Dth Docket No. 3401
Jun-04
Sep-04
Dec-04
Mar-05
Jun-05
Sep-05
Dec-05
Mar-06
Jun-06
Sep-06
Dec-06
Mar-07
Jun-07
Sep-07
Dec-07

Data Request TEC-RI 1-70

Request:

Please provide the actual historic experience concerning the nature of the customers lost and gained in the Large Low Load Factor, Large High Load Factor, Extra Large Low Load Factor, and Extra Large High Load Factor classes. Please go back 7 years: year ending September 30, 2001 through year ending September 30, 2007. For each class and year, please show (1) the revenue per customer for the prior year, (2) number of customers lost that year in the class, (3) average revenue in the prior year for the customers lost, (3) number of customers gained that year in that class, and (4) average revenue in the next year for the customers gained.

Response:

The Company does not track or accumulate the required information necessary to answer this request.

Prepared by or under the supervision of: Peter Czekanski

Data Request TEC-RI 1-76

Request:

Mr. Simpson, on page 13 of his testimony, states that "the vast majority of LDCs have implemented decoupling mechanisms that account for the revenue impact of both weather and non-weather related changes in customer usage. These LDCs are listed in Attachment NG-JDS-3. Please provide data to substantiate the claim that the LDCs listed in Attachment NG-JDS-3 constitute the vast majority of LDCs.

Response:

As explained in the Company's response to Data Request DIV-7-19(c), the statement that "the vast majority of LDCs have implemented decoupling mechanisms that account for the revenue impact of both weather and non-weather related changes in customer usage" is referring to Attachment NG-JDS-3 and to the utilities that are included in Attachment NG-JDS-3. As explained in the response to Data Request DIV 7-19(b), above, 19 out of 25, or 76% - a vast majority - of decoupling mechanisms that have been implemented or been proposed to be implemented[1] account for the revenue impact of both weather and non-weather related customer usage.

---

[1] And are waiting for a final regulatory decision on the decoupling proposal.

Data Request TEC-RI 1-77

Request:

How many state public utility commissions have approved decoupling for LDCs?

Response:

An analysis of Attachment NG-JDS-3 indicates that as of the date that the attachment was prepared, 12 states had approved decoupling mechanisms. Based on updated research as of June 2008, a total of 15 states have now approved decoupling mechanisms. An updated version of Attachment NG-JDS-3 is provided herewith as Attachment TEC-RI-1-77.

In addition, two states have approved decoupling approaches based on rate design rather than decoupling mechanisms. Missouri has approved rates that recover the residential class distribution revenue requirement through fixed monthly customer charges and Georgia has approved rates that recover revenue requirements to all classes through fixed monthly customer charges and customer specific demand charges.

Prepared by or under the supervision of: James Simpson

	State	Company	Docket number	Date of Decision	Basis for Rate Adjustments	Classes	Period	Additional Information; Additional Clauses
1	AR	Arkansas Oklahoma Gas Corp.	D-07-026-U	11/20/2007	Annual weather normalized actual class revenues compared to target (rate case) revenues[1]	Residential and Small Business	Annual true up; Nov 1 – Oct 31	WNA[2] CGA[3] Municipal Tax Clause
2	AR	Arkansas Western Gas	D-06-124-U	7/13/2007	Annual actual revenues compared to rate case revenues[4] No class true up if (1) customers and volumes or (2) revenues are ≥ TY levels Separate WNA	Residential (RS-l), Business 1- Sales and Transport (B-l), and Business 2-Sales and Transport (B-2) rate classes.	Annual true up, August – July; adjustment rate in effect following January through December	WNA Tax and fee
3	AR	CenterPoint Arkansas	06- 16 1 -U	10/25/07	Annual actual revenues compared to rate case revenues[18] No class true up if (1) customers and volumes or (2) revenues are ≥ TY levels WNA currently in effect[1]	Residential Firm Sales Service, RS-1, Small Commercial Firm Sales Service, SC-1, Small Commercial Firm Sales Service - Off Peak, SCS-2	Annual true up, January – December adjustment rate in effect following July through June	WNA
4	CA	PG&E	AP-9712020De-0002046	5/27/2004	Rate Plan Revenue Requirement	All	Annual	23 Balancing accounts, Adjustments • Core, non-core fixed cost; pension contribution 7 memo accounts • Catastrophic Event, Advanced Metering Infrastructure, Financial Hedging

[1] This atypical decoupling feature was designed to address the atypical condition of declining customers, declining Mcf
[2] WNA: Weather Normalization adjustment clause.; WN: weather normalized
[3] CGA: Cost of Gas Adjustment clause.
[4] This atypical decoupling feature was designed to address the atypical condition of declining customers, declining Mcf

	State	Company	Docket number	Date of Decision	Basis for Rate Adjustments	Classes	Period	Additional Information; Additional Clauses
5	CA	SOCal Gas		1998	PBR[5] price cap rate plan	All	Annual	18 Balancing Accounts • Pension, PBOP[6], Core, non-core fixed cost 26 memo accounts • Catastrophic Event, Intervenor Award ESM[7]
6	CA	Southwest Gas		3/16/2004	Rate plan revenue requirement Attrition year increases could be adjusted down if pipe replacement targets missed Actual margin revenues compared to authorized levels	All	Annual	Catastrophic Event, Public Purpose Program, Low Income Energy Efficiency
7	CO	Public Service Co. of CO	D-06S-656G	6/18/2007	NUPC true up mechanism Difference between WN actual use per customer and TY UPC, times margin rate times actual customers	Residential RG	Annual	
8	IL	Central Illinois Light Co.	D-07-0588	Pending filed 11/2/2007	Billing month adjustment: the difference between actual class revenues per actual customer vs. TY revenues per TY customer, multiplied by TY customers, plus prior year reconciliation	Residential (GDS-1), Small General (GDS-2)	Monthly with 2 month lag between calculation and billing of adjustment	Uncollectibles CGA Environmental Remediation costs Franchise cost adjustment Government Compliance cost adjustment

5 PBR: Performance Based Ratemaking
6 PBOP: Post-retirement other than Pension expense
7 ESM: Earnings Sharing Mechanism

	State	Company	Docket number	Date of Decision	Basis for Rate Adjustments	Classes	Period	Additional Information; Additional Clauses
9	IL	Central Illinois Public Service Co.	D-07-0589	Pending filed 11/2/2007	Billing month adjustment: the difference between actual class revenues per actual customer vs. TY revenues per TY customer, multiplied by TY customers, plus prior year reconciliation	Residential (GDS-1), Small General (GDS-2)	Monthly with 2 month lag between calculation and billing of adjustment	Uncollectibles CGA Environmental Remediation costs Franchise cost adjustment Government Compliance cost adjustment
10	IL	Illinois Power Co.	D-07-0590	Pending filed 11/2/2007	Billing month adjustment: the difference between actual class revenues per actual customer vs. TY revenues per TY customer, multiplied by TY customers, plus prior year reconciliation	Residential (GDS-1), Small General (GDS-2)	Monthly with 2 month lag between calculation and billing of adjustment	Uncollectibles CGA Environmental Remediation costs Franchise cost adjustment Government Compliance cost adjustment
11	IL	Peoples Gas Light and Coke Co. and North Shore Gas Co.	D-07-0241, 0242	Pending	Monthly difference between actual and TY[8] ("Test Year") margin per customer, times TY customers, divided by estimated volumes, 2 months later. Actual and target revenues is deferred	Service classes 1N, 1H, and 2	Monthly	CGA Municipal taxes Environmental costs
12	IN	Southern Indiana Gas and Electric	C- 43046 C-43112	12/1/2006 8/1/2007	85% of difference between actual class margins and TY margins by class, adj for growth in customers	Residential, General Service sales; School transportation	Annual recovery of accumulated deferred balance; with reconciliation	Bad debt gas , pipeline safety, incremental O&M from Pipeline Safety Improvement Act of 2002. (PSA), normal temperature adjustment
13	KS	Atmos Energy Corp	D-08-ATMG-280-RTS	Pending filed 9/14/2007	Difference between test-year average margin per customer and actual average margin per customer (including margins from the WN adjustment) times the monthly average number of billing units for the accounting/recovery period	All Residential, Commercial, Public Authority Bills	Annual	WNA separate

[8] TY: Test year

	State	Company	Docket number	Date of Decision	Basis for Rate Adjustments	Classes	Period	Additional Information; Additional Clauses
14	LA	Atmos - LA	Order U-28814	7/20/06	Rates adjusted annually to recover projected revenue requirement from projected billing determinants; projected and actual revenues are reconciled	All	Annual	WNA
15	MD	Washington Gas Light Company	Case No. 8990	8/6/2005	Calculate billing month adjustment based on actual class revenues vs. TY revenues, adjusted for customer growth Reconciliation of actual and target revenues	Rate Schedule Nos. 1, 1A, 2, 2A, 3 and 3A	Monthly with 2 month lag	
16	MS	Atmos - MS	Docket 92-UN-0230	10/1/1993	Rates adjusted annually to recover projected revenue requirement from projected billing determinants; projected and actual revenues are reconciled	All classes except Flex Rate; Spot sales / transportation; Municipal	Annual	WNA
17	NC	Piedmont Natural Gas	D-G-9,SUB499	11/3/2005	Rev Adj by class by month = Target revenues – Actual revenues.: Target: actual customers x (TY base load/cust + TY TS factor x Normal HDD) Interest on deferred	Rate schedules 101, 121, 102, 132, 152, 162	Adj Factor changes Apr, Nov, based on deferred bal at Jan, Aug	Pipeline integrity, PBOP regulatory assets Bad debt (gas)
18	NJ	South Jersey Gas /New Jersey Natural Gas	Docket GR 05121020	11/9/2006	Monthly difference between current actual and TY NUPC, times predetermined weighted margin per therm times actual monthly customers Capped to limit ROE to 10.5%	Resid, Resid Transport, Gen Svc High LF, Comprehensive Transportation and Balancing, Gen Svc Low LF, Small Commercial Rebundled Trans, ED	Annual	WNA

	State	Company	Docket number	Date of Decision	Basis for Rate Adjustments	Classes	Period	Additional Information; Additional Clauses
19	NY	Con Ed	06-G-1332	9/25/2007	Difference between rate case rate year revenue per customer and actual rate year revenue per customer, times actual rate year customers.	SC No. 2 - Rate I; SC No. 2 - Rate II; SC No. 3 customers with 1-4 dwelling units; and SC No. 3 customers with more than 4 dwelling units, SC No. 9; excluding customers taking service under special rates ED, Low Income, Manuf, Econ by pass	Annual	WNA ESM Trackers for: property taxes, non-Company labor interference expenses, Cap Ex, PBOP, Gas transmission main maintenance, R&D, environmental remediation, pipeline integrity programs, distribution integrity and/or gas inspections
20	NY	National Fuel	C-07-G-0141	12/21/2007	Difference between annual TY UPC and current year WN UPC, times tail block rate times customers	SC 1, SC 2, SC 2A (Res) and SC 3. (GS)	Annually; 12 months ended December data. Effective March 1	WNA
21	OH	Dominion East Ohio	C-07-829-GA-AIR	Pending filed 8/30/2007	Difference between order-granted revenues and actual WN revenues with order-granted revenues adjusted to reflect growth in number of customers	GSS, LVGSS, ECTS, LVECTS	New rate effective November 1 annually	Low income subsidy adjustment Uncollectible adjustment
22	OH	Duke Energy Ohio, Inc.	C-07-589-GA-AIR	Pending filed 7/17/2007	Difference between order-granted revenues and actual WN revenues with order-granted revenues adjusted to reflect growth in number of customers	All sales & transportation customers except Rate IT	Annual	Main replacement rider Low income subsidy adjustment Uncollectible adjustment
23	OH	Vectren	05-1444-GA-UNC	9/13/2006	Difference in actual WN revenues, rate case revenues, adjusted for growth in customers. Actual and target revenues are reconciled	Residential sales/ trans: general sales / trans	New rate effective November 1 annually,	

	State	Company	Docket number	Date of Decision	Basis for Rate Adjustments	Classes	Period	Additional Information; Additional Clauses
24	OR	Northwest	Renew: UG 163	8/22/2003 Initial: 9/12/02; renew 8/25/05	Partial decoupling: Base line rate case per customer adjusted for price elasticity compared to actual WN UPC	Res 1, 2 Commercial 1, 3, 31	Annual, eff Oct 1 each year; adj based on deferred balance as of June 30.	Separate WNA
25	RI	National Grid RI	Docket No. 3943	Pending filed 4/1/2008	Difference between rate case margin per customer, and actual revenue, times actual monthly customers, Reconciling	All classes; new large and extra large requiring customer connect investment excluded	New rate effective November 1 annually,	WNA currently effective
26	SC	Piedmont - SC	Docket 2005-125-G	9/27/2007	Projected ROE compared to PSC SC allowed ROE; adjustments to rates allowed	All		
27	UT	Questar Gas	Docket No. 05-057-T01	5/26/2006	Difference between rate case margin per customer, and actual revenue, times actual monthly customers, Reconciling	GS-1, GSS	Semiannually, adjustment to base rates made to amortize current balance over 12 months	WNA: separate
28	WA	Avista	UG 060518	12/21/2005	Actual WN sales, with new customers removed, compared to TY monthly sales. revenues calculated by multiplying sales diff by approved rate; 90% of diff is deferred Deferral subject to ESM and DSM performance Impact capped at 2%; difference remains in deferred.	RS 101 (residential and small commercial)	Annual, July – June; new adjustment effective Sept 1 Nov 07 – Oct 2010	Tax Adjustment

	State	Company	Docket number	Date of Decision	Basis for Rate Adjustments	Classes	Period	Additional Information; Additional Clauses
29	WA	Cascade Natural Gas Corp	UG-060256	1/12/2007	Difference between rate case margin per customer and actual WN margin per customer times actual customers Actual and target revenues reconciled	RS 503, 504 (Residential, Commercial)	Annual	

Generic Investigations:

- Delaware Pending case (Regulation Docket No. 59): PSC is considering implementing revenue decoupling mechanisms
- Massachusetts 07-50
- New Hampshire

Data Request TEC-RI 1-78

Request:

Concerning the LDCs listed in Attachment NG-JDS-3, how many of these 25 LDCs use Revenue per Customer (or use per customer) mechanism for decoupling? Of the LDCs that use Revenue per Customer (or use per customer), how many include the largest firm commercial and industrial class? Of those that use Revenue or use per customer mechanism for decoupling, and considering the rate class eligibility rules, please identify the Commercial & Industrial rate classes that are EXCLUDED from the decoupling mechanism, and the low and high end in terms of therms per year usage for customer eligibility in that each class. By way of illustration, the Large (High and Low Factor) rate classes for National Grid Rhode Island are available to customers with annual gas usage that is greater than 35,000 therms but less than 150,000 therms.

Response:

Of the 25 LDCs listed in Attachment NG-JDS-3, 22 companies use[1] RPC or use per customer ("UPC") decoupling mechanisms; the three exceptions are the California LDCs, which true up company total revenue requirements established in multi-year rate plans, to company total actual revenues.

Of the 22 LDCs that use RPC or UPC decoupling mechanisms, the following apply the decoupling mechanism to all major residential, commercial and industrial rate classes; all other decoupling mechanisms exclude some classifications on the basis of size, classification (e.g. "industrial") or service type (e.g. transportation):

- Con ED, New York[2]
- National Fuel, New York
- Washington Gas Light, Maryland
- Duke Energy, Ohio

Concentric's research does not include the additional detailed information asked for in this request concerning the annual usage limits of the classes that are excluded from each LDC's decoupling mechanism.

[1] Approved, or pending regulatory order.
[2] Cod Ed residential non-heating customers are excluded; all major C&I classifications are included.

Data Request TEC-RI 1-79

Request:

Concerning the AGA Elasticity Report (Attachment NG-JDS-12), witness Simpson on page 29 of his testimony cites a decrease of 4.9% per year between 2004 and 2006 experienced by the participating LDCs, and further that this is consistent with and validates the 3.3% per year decrease in annual NUPC that National Grid experienced during the same period. Of the 4.9% decrease per year, what share is attributable to LDC energy efficiency programs? Of the 3.3% per year decrease, what share is attributable to National Grid gas energy efficiency programs? What does this say concerning the relative effectiveness of gas prices and non-utility incentivized conservation on the one had, and utility sponsored conservation on the other hand, in achieving the NARUC goal of slowing the rate of demand growth of natural gas.

Response:

The information requested concerning the portion of total conservation that is attributable to LDC-provided efficiency programs is not available. However, the relative effectiveness of gas prices and non-utility incentivized conservation on the one hand, and utility sponsored conservation on the other hand is not relevant to the issue of the appropriateness of utility sponsored conservation programs. Utility sponsored conservation programs are widely regarded as necessary actions to addressing market barriers that prevent the full implementation of all cost effective energy efficiency measures.

Prepared by or under the supervision of: James Simpson

Data Request TEC-RI 1-80

Request:

Why are revenues from NGV and Gas Lights included with C&I Small and Residential Heating, respectively? Is the billing determinants for NGV and Gas Lights similarly included with these classes?

Response:

NGV service is used for commercial service and given this type of the load it seemed appropriate to include the NGV service with the C&I Small. Similarly Gas Lights service is a residential type service and was included in Residential Heating.

The usage determinants should have been included in the Small C&I and Residential Heating class but were inadvertently omitted.

Prepared by or under the supervision of: David Heintz

Data Request TEC-RI 1-81

Request:

Please explain how the allocation of revenues to rate classes factors into the COSS.

Response:

Revenues at current rates are compared to allocated costs to determine the current net income and rate of return by rate class as shown on NG-DAH-2, page 1, lines 14 and 15. The return at current rates is a factor considered in the distribution of the revenue increase.

Prepared by or under the supervision of: David Heintz

Data Request TEC-RI 1-82

Request:

How are the costs related to the Manchester Special Contract and Marketer Services allocated to rate classes?

Response:

There is no explicit allocation to rate classes of costs related to the Manchester Special Contract or Marketer Services. Instead, the revenues from these services are allocated to the classes as a credit to the cost of service on factors that reflect the type of service. The Manchester revenues are allocated using the RSUM, which reflects overall system usage. The marketer revenues are allocated on the basis of transportation customers.

Prepared by or under the supervision of: David Heintz

Data Request TEC-RI 1-83

Request:

Is the RSUM factor used to allocate demand, customer, or commodity related costs?

Response:

The RSUM factor is used to allocate demand costs.

Data Request TEC-RI 1-84

Request:

Is total sales a measure of demand or commodity?

Response:

Total sales or “throughput” can be a measure of either demand or commodity.

Data Request TEC-RI 1-85

Request:

Is class responsibility under design winter temperatures a measure of demand or commodity?

Response:

Assuming class responsibility is referring to throughput at design winter temperatures, it can be either a measure of demand or commodity.

Prepared by or under the supervision of: David Heintz

Data Request TEC-RI 1-86

Request:

Are production costs considered demand related or commodity related?

Response:

The production costs in this case are related to on-system storage costs. The fixed costs related to this function are considered demand.

Prepared by or under the supervision of: David Heintz

Data Request TEC-RI 1-87

Request:

Where in the filing is the RSUM study provided?

Response:

Please see Workpapers DAH, pages 41 – 44 for the calculation of the RSUM factor. Workpapers DAH, pages 45 – 48 contain the calculations for the RSUM LT 4 factor.

Prepared by or under the supervision of: David Heintz

Data Request TEC-RI 1-88

Request:

Where in the filing is the Design Winter Study provided?

Response:

Please see Workpapers DAH, pages 53 – 55.

Prepared by or under the supervision of: David Heintz

Data Request TEC-RI 1-89

Request:

Please provide the equivalent to Attachment NG-DAH-2 from the last rate case, Docket 3401.

Response:

Please see the attached schedules.

Prepared by or under the supervision of: David Heintz

New England Division
Cost of Service Study
Income and Rates of Return at Present Rates

Line No.	Description	Total Company	Residential Non-Heating	Residential Heating	Total Residential	C&I Small	C&I Medium	C&I Large	C&I Extra-Lg.	NGV	Gas Lamps
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	REVENUES:										
1	Operating Revenues										
2	Non Gas Revenues	$134,208,789	$6,812,483	$86,941,546	$93,754,029	$12,078,011	$16,340,591	$8,253,245	$3,758,937	$21,593	$2,382
3	Gas Revenues	0	0	0	0	0	0	0	0	0	0
4	Base Tariff	$134,208,789	$6,812,483	$86,941,546	$93,754,029	$12,078,011	$16,340,591	$8,253,245	$3,758,937	$21,593	$2,382
5	CGA Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6	Total Operating Revenues	$134,208,789	$6,812,483	$86,941,546	$93,754,029	$12,078,011	$16,340,591	$8,253,245	$3,758,937	$21,593	$2,382
7	Other Revenues	$3,901,591	$116,731	$2,372,688	$2,489,419	$430,180	$568,831	$272,506	$138,059	$2,270	$327
8	Revenues shifted to CGA	0	0	0	0	0	0	0	0	0	0
9	Gross Operating Revenues	$138,110,380	$6,929,214	$89,314,234	$96,243,448	$12,508,191	$16,909,422	$8,525,751	$3,896,996	$23,863	$2,709
10	Less: Gross Receipts Tax	($7,622,472)	($290,609)	($5,092,446)	($5,383,055)	($717,525)	($931,965)	($426,760)	($162,639)	($529)	$0
11	Net Operating Revenues	$130,487,908	$6,638,605	$84,221,788	$90,860,393	$11,790,666	$15,977,457	$8,098,991	$3,734,358	$23,334	$2,709
	EXPENSES:										
12	Cost of Gas										
13	Base Tariff	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
14	CGA	0	0	0	0	0	0	0	0	0	0
15	Total Cost of Gas	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
16	Other Operation & Maintenance Expense	$68,120,585	$6,652,014	$48,183,319	$54,835,333	$5,743,138	$4,861,235	$1,741,088	$923,070	$13,624	$3,097
17	Depreciation	$20,988,002	1,904,155	14,098,648	16,002,803	2,026,464	1,776,690	704,990	470,308	5,934	812
18	Taxes Other Than Income Taxes	$11,691,242	1,066,029	8,069,922	9,135,951	1,116,300	940,599	344,033	150,446	3,317	597
19	Franchise & Gross Receipts Taxes	$7,622,472	290,609	5,092,446	5,383,055	717,525	931,965	426,760	162,639	529	0
20	Total Expenses	$108,422,301	$9,912,808	$75,444,335	$85,357,142	$9,603,427	$8,510,490	$3,216,870	$1,706,462	$23,404	$4,506
21	Income Before Income Taxes	$29,688,080	($2,983,594)	$13,869,900	$10,886,306	$2,904,764	$8,398,932	$5,308,881	$2,190,535	$459	($1,797)
22	Income Taxes	($5,863,098)	($493,474)	($4,130,591)	($4,624,064)	($527,595)	($465,035)	($181,165)	($62,961)	($1,941)	($337)
23	Net Operating Income	$23,824,982	($3,477,067)	$9,739,309	$6,262,242	$2,377,169	$7,933,897	$5,127,715	$2,127,573	($1,482)	($2,133)
24	Reallocation of Non Traditional Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
25	Net Utility Operating Income	$23,824,982	($3,477,067)	$9,739,309	$6,262,242	$2,377,169	$7,933,897	$5,127,715	$2,127,573	($1,482)	($2,133)
26	Rate Base	$271,102,398	$22,817,613	$190,993,398	$213,811,012	$24,395,330	$21,502,639	$8,376,858	$2,911,252	$89,742	$15,566
27	Reallocation of Non Traditional Rate Base		$0	$0	$0	$0	$0	$0	$0	$0	$0
28	Reallocated Rate Base	$271,102,398	$22,817,613	$190,993,398	$213,811,012	$24,395,330	$21,502,639	$8,376,858	$2,911,252	$89,742	$15,566
29	Rate of Return	8.79%	-15.24%	5.10%	2.93%	9.74%	36.90%	61.21%	73.08%	-1.65%	-13.70%
30	Unitized Return	1.00	-1.73	0.58	0.33	1.11	4.20	6.97	8.32	-0.19	-1.56
31	Required Increase for Equalized ROR	$0	$5,482,322	$7,045,545	$12,527,867	($233,262)	($6,044,205)	($4,391,541)	($1,871,727)	$9,368	$3,501
32	Total Revenues at Equalized ROR	$134,208,789	$12,294,805	$93,987,091	$106,281,896	$11,844,749	$10,296,386	$3,861,704	$1,887,210	$30,961	$5,883

New England Division
Cost of Service Study
Income and Rates of Return at Proposed Rates

Line No.	Description	Total Company	Residential Non-Heating	Residential Heating	Total Residential	C&I Small	C&I Medium	C&I Large	C&I Extra-Lg.	NGV	Gas Lamps
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	REVENUES:										
1	Non Gas Revenues	$140,544,175	$7,203,682	$92,336,372	$99,540,054	$12,715,700	$17,163,620	$7,968,612	$3,132,213	$21,593	$2,382
2	Gas Revenues	0	0	0	0	0	0	0	0	0	0
3	Base Revenues	$140,544,175	$7,203,682	$92,336,372	$99,540,054	$12,715,700	$17,163,620	$7,968,612	$3,132,213	$21,593	$2,382
4	CGA Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5	Total Operating Revenues	$140,544,175	$7,203,682	$92,336,372	$99,540,054	$12,715,700	$17,163,620	$7,968,612	$3,132,213	$21,593	$2,382
6	Other Revenues	$3,901,591	$116,731	$2,372,688	$2,489,419	$430,180	$568,831	$272,506	$138,059	$2,270	$327
7	Gross Operating Revenues	$144,445,766	$7,320,413	$94,709,060	$102,029,473	$13,145,880	$17,732,451	$8,241,118	$3,270,272	$23,863	$2,709
8	Less: Gross Receipts Tax	($7,622,472)	($290,609)	($5,092,446)	($5,383,055)	($717,525)	($931,965)	($426,760)	($162,639)	($529)	$0
9	Net Operating Revenues	$136,823,294	$7,029,804	$89,616,614	$96,646,418	$12,428,355	$16,800,486	$7,814,358	$3,107,634	$23,334	$2,709
	EXPENSES										
10	Cost of Gas										
11	Base Tariff	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
12	CGA	0	0	0	0	0	0	0	0	0	0
13	Total Cost of Gas	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
14	Other Operation & Maintenance Expense	$68,283,022	$6,666,839	$48,320,658	$54,987,497	$5,749,358	$4,864,139	$1,742,113	$923,194	$13,624	$3,097
15	Depreciation	20,988,002	1,904,155	14,098,648	16,002,803	2,026,464	1,776,690	704,990	470,308	5,934	812
16	Taxes Other Than Income Taxes	11,691,242	1,066,029	8,069,922	9,135,951	1,116,300	940,599	344,033	150,446	3,317	597
17	Franchise & Gross Receipts Taxes	7,622,472	290,609	5,092,446	5,383,055	717,525	931,965	426,760	162,639	529	0
18	Total Expenses	$108,584,738	$9,927,633	$75,581,673	$85,509,306	$9,609,648	$8,513,393	$3,217,895	$1,706,586	$23,404	$4,506
19	Income Before Income Taxes	$35,861,029	($2,607,220)	$19,127,387	$16,520,168	$3,536,232	$9,219,057	$5,023,223	$1,563,686	$459	($1,797)
20	Income Taxes	($8,262,470)	($695,419)	($5,820,964)	($6,516,383)	($743,504)	($655,342)	($255,304)	($88,727)	($2,735)	($474)
21	Net Operating Income	$27,598,559	($3,302,639)	$13,306,423	$10,003,784	$2,792,729	$8,563,715	$4,767,918	$1,474,959	($2,276)	($2,271)
22	Reallocation of Non Traditional Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
23	Net Utility Operating Income	$27,598,559	($3,302,639)	$13,306,423	$10,003,784	$2,792,729	$8,563,715	$4,767,918	$1,474,959	($2,276)	($2,271)
24	Rate Base	$271,102,398	$22,817,613	$190,993,398	$213,811,012	$24,395,330	$21,502,639	$8,376,858	$2,911,252	$89,742	$15,566
25	Reallocation of Non Traditional Rate Base		$0	$0	$0	$0	$0	$0	$0	$0	$0
26	Reallocated Rate Base	$271,102,398	$22,817,613	$190,993,398	$213,811,012	$24,395,330	$21,502,639	$8,376,858	$2,911,252	$89,742	$15,566
27	Rate of Return	10.18%	-14.47%	6.97%	4.68%	11.45%	39.83%	56.92%	50.66%	-2.54%	-14.59%
28	Unitized Return	1.00	-1.42	0.68	0.46	1.12	3.91	5.59	4.98	-0.25	-1.43
29	Required Investment for Equalized ROR	0	5,625,500	6,136,940	11,762,440	(309,254)	(6,374,720)	(3,915,144)	(1,178,590)	11,412	3,856

New England Division
Cost of Service Study
Total Operations and Maintenance Expenses

Line No.	Description	Total Company	Residential Non-Heating	Residential Heating	Total Residential	C&I Small	C&I Medium	C&I Large	C&I Extra-Lg.	NGV	Gas Lamps
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	I. Production Expenses										
1	Demand	$200,082	$3,442	$112,991	$116,433	$17,008	$31,223	$18,579	$16,764	$64	$10
2	Customer	0	0	0	0	0	0	0	0	0	0
3	Commodity	0	0	0	0	0	0	0	0	0	0
4	Seasonal	0	0	0	0	0	0	0	0	0	0
5	Total	$200,082	$3,442	$112,991	$116,433	$17,008	$31,223	$18,579	$16,764	$64	$10
	II. Storage and Processing Expenses										
6	Demand	$226,453	$3,896	$127,884	$131,780	$19,250	$35,338	$21,027	$18,974	$73	$11
7	Customer	0	0	0	0	0	0	0	0	0	0
8	Commodity	0	0	0	0	0	0	0	0	0	0
9	Seasonal	0	0	0	0	0	0	0	0	0	0
10	Total	$226,453	$3,896	$127,884	$131,780	$19,250	$35,338	$21,027	$18,974	$73	$11
	III. Transmission Expenses										
11	Demand	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
12	Customer	0	0	0	0	0	0	0	0	0	0
13	Commodity	0	0	0	0	0	0	0	0	0	0
14	Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	IV. Distribution Expenses										
15	Demand	$6,407,822	$157,489	$4,396,717	$4,554,206	$649,773	$774,550	$329,197	$95,626	$3,911	$559
16	Customer	8,656,610	1,171,217	5,713,408	6,884,625	906,316	722,069	122,114	20,867	619	0
17	Commodity	1,971,800	44,923	1,056,997	1,101,920	151,166	311,579	187,230	218,491	1,235	178
18	Total	$17,036,232	$1,373,629	$11,167,123	$12,540,751	$1,707,255	$1,808,199	$638,541	$334,984	$5,765	$736
	V. Customer Accts., Svc. and Sales Exp.										
19	Demand	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
20	Customer	19,554,019	2,317,049	15,691,831	18,008,880	1,105,937	343,017	83,949	11,220	206	810
21	Commodity	0	0	0	0	0	0	0	0	0	0
22	Total	$19,391,582	$2,302,224	$15,554,493	$17,856,716	$1,099,716	$340,113	$82,924	$11,096	$206	$810
	VI. Admin & General, Pro Forma Test Year Expense										
23	Demand	$8,288,381	$195,932	$5,558,992	$5,754,924	$823,174	$1,038,964	$469,560	$196,322	$4,754	$683
24	Customer	$18,632,282	$2,618,345	$13,110,505	15,728,851	$1,717,122	$992,712	$164,252	$27,785	$964	$598
25	Commodity	$4,345,571	$154,547	$2,551,331	2,705,878	$359,613	$614,686	$346,205	$317,144	$1,798	$248
26	Total	$31,266,235	$2,968,824	$21,220,829	$24,189,652	2,899,908	2,646,362	980,017	541,251	7,516	1,529
	Total Operations and Maintenance Expense										
27	Demand	$15,122,739	$360,759	$10,196,584	$10,557,343	$1,509,205	$1,880,076	$838,364	$327,686	$8,802	$1,263
28	Customer	46,842,912	6,106,610	34,515,745	40,622,355	3,729,374	2,057,798	370,315	59,872	1,789	1,408
29	Commodity	6,317,371	199,470	3,608,328	3,807,798	510,779	926,265	533,434	535,635	3,033	426
30	Seasonal	0	0	0	0	0	0	0	0	0	0
31	Total	$68,283,022	$6,666,839	$48,320,658	$54,987,497	$5,749,358	$4,864,139	$1,742,113	$923,194	$13,624	$3,097

New England Division
Cost of Service Study
Total Rate Base

Line No.	Description	Total Company	Residential Non-Heating	Residential Heating	Total Residential	C&I Small	C&I Medium	C&I Large	C&I Extra-Lg.	NGV	Gas Lamps
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	I. GROSS PLANT IN SERVICE										
1	Demand	$232,411,551	$5,583,529	$157,351,229	$162,934,758	$23,281,297	$28,706,363	$12,663,395	$4,669,320	$136,816	$19,603
2	Customer	269,388,147	38,775,874	192,836,166	231,612,040	25,133,096	10,580,208	1,722,576	321,964	12,530	5,733
3	Commodity	4,375,520	99,721	2,345,670	2,445,391	335,461	691,364	415,430	484,739	2,740	395
4	Total	$506,175,218	$44,459,124	$352,533,065	$396,992,189	$48,749,855	$39,977,935	$14,801,400	$5,476,022	$152,085	$25,731
	II. ACCUMULATED RESERVE FOR DEPRECIATION										
5	Demand	$94,335,061	$2,228,040	$63,237,712	$65,465,752	$9,364,642	$11,834,501	$5,355,461	$2,252,909	$54,035	$7,761
6	Customer	131,194,840	18,768,260	93,945,470	112,713,730	12,518,812	5,016,562	788,470	148,632	6,510	2,124
7	Commodity	2,604,672	59,364	1,396,344	1,455,709	199,695	411,555	247,296	288,551	1,631	235
8	Total	$228,134,573	$21,055,664	$158,579,527	$179,635,190	$22,083,150	$17,262,618	$6,391,227	$2,690,092	$62,176	$10,120
	III. NET UTILITY PLANT										
9	Demand	$138,076,491	$3,355,489	$94,113,517	$97,469,006	$13,916,655	$16,871,862	$7,307,934	$2,416,411	$82,781	$11,842
10	Customer	138,193,307	20,007,614	98,890,696	118,898,310	12,614,284	5,563,646	934,106	173,332	6,019	3,609
11	Commodity	1,770,848	40,357	949,325	989,682	135,766	279,809	168,134	196,187	1,109	160
12	Total	$278,040,645	$23,403,460	$193,953,539	$217,356,999	$26,666,706	$22,715,317	$8,410,173	$2,785,930	$89,909	$15,611
	IV. WORKING CAPITAL										
13	Demand	$6,270,804	$136,076	$4,005,550	$4,141,626	$595,752	$844,071	$423,671	$262,108	$3,121	$455
14	Customer	6,142,639	861,089	4,419,544	5,280,633	551,548	258,937	43,400	7,692	277	152
15	Commodity	2,814,665	80,967	1,867,739	1,948,705	266,933	358,530	163,368	74,679	2,142	308
16	Seasonal	0	0	0	0	0	0	0	0	0	0
17	Total	$15,228,108	$1,078,132	$10,292,833	$11,370,965	$1,414,233	$1,461,538	$630,439	$344,478	$5,540	$915
	V. RATE BASE ADJUSTMENTS										
18	Demand	($8,784,953)	($211,130)	($5,949,015)	($6,160,145)	($880,185)	($1,084,706)	($478,229)	($175,773)	($5,175)	($741)
19	Customer	(13,267,190)	(1,450,245)	(7,242,732)	(8,692,977)	(2,796,668)	(1,571,464)	(174,681)	(30,731)	(462)	(208)
20	Commodity	(114,212)	(2,603)	(61,227)	(63,830)	(8,756)	(18,046)	(10,844)	(12,653)	(72)	(10)
21	Total	($22,166,355)	($1,663,978)	($13,252,974)	($14,916,952)	($3,685,609)	($2,674,216)	($663,754)	($219,156)	($5,708)	($960)
	VI. TOTAL RATE BASE										
22	Demand	$135,562,341	$3,280,435	$92,170,053	$95,450,488	$13,632,222	$16,631,227	$7,253,376	$2,502,746	$80,728	$11,555
23	Customer	131,068,756	19,418,458	96,067,509	115,485,966	10,369,165	4,251,119	802,825	150,293	5,835	3,554
24	Commodity	4,471,301	118,721	2,755,837	2,874,557	393,942	620,293	320,658	258,213	3,179	457
25	Seasonal	0	0	0	0	0	0	0	0	0	0
26	Total	$271,102,398	$22,817,613	$190,993,398	$213,811,012	$24,395,330	$21,502,639	$8,376,858	$2,911,252	$89,742	$15,566

New England Division
Cost of Service Study
Plant In Service

Line No.	Description	Total Company	Residential Non-Heating	Residential Heating	Total Residential	C&I Small	C&I Medium	C&I Large	C&I Extra-Lg.	NGV	Gas Lamps
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	I. INTANGIBLE PLANT										
1	Demand	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2	Customer	47,291,500	7,085,968	35,623,171	42,709,139	3,646,378	818,441	95,181	16,424	1,187	4,749
3	Commodity	351,454	8,007	188,399	196,407	26,944	55,536	33,372	38,944	220	32
4	Subtotal	$47,642,954	$7,093,975	$35,811,571	$42,905,546	$3,673,321	$873,977	$128,553	$55,368	$1,407	$4,781
	II. PRODUCTION PLANT										
5	Demand	$3,189,705	$54,876	$1,801,308	$1,856,184	$271,145	$497,757	$296,180	$267,255	$1,026	$158
6	Customer	0	0	0	0	0	0	0	0	0	0
7	Commodity	0	0	0	0	0	0	0	0	0	0
8	Subtotal	$3,189,705	$54,876	$1,801,308	$1,856,184	$271,145	$497,757	$296,180	$267,255	$1,026	$158
	III. STORAGE AND PROCESSING PLANT										
9	Demand	$12,547,097	$215,860	$7,085,666	$7,301,526	$1,066,583	$1,957,987	$1,165,059	$1,051,282	$4,038	$621
10	Customer	0	0	0	0	0	0	0	0	0	0
11	Commodity	0	0	0	0	0	0	0	0	0	0
12	Subtotal	$12,547,097	$215,860	$7,085,666	$7,301,526	$1,066,583	$1,957,987	$1,165,059	$1,051,282	$4,038	$621
	IV. TRANSMISSION PLANT										
13	Demand	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
14	Customer	0	0	0	0	0	0	0	0	0	0
15	Commodity	0	0	0	0	0	0	0	0	0	0
16	Subtotal	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	V. DISTRIBUTION PLANT										
17	Demand	$204,355,729	$5,022,578	$140,218,355	$145,240,933	$20,722,305	$24,701,647	$10,498,636	$3,049,670	$124,724	$17,814
18	Customer	193,257,704	27,609,152	137,065,163	164,674,315	18,787,286	8,160,683	1,364,488	261,114	9,791	27
19	Commodity	0	0	0	0	0	0	0	0	0	0
20	Subtotal	$397,613,433	$32,631,729	$277,283,518	$309,915,248	$39,509,590	$32,862,330	$11,863,124	$3,310,784	$134,515	$17,841
	VI. GENERAL PLANT										
21	Demand	$12,319,020	$290,215	$8,245,900	$8,536,115	$1,221,264	$1,548,972	$703,520	$301,112	$7,027	$1,010
22	Customer	28,838,943	4,080,754	20,147,832	24,228,586	2,699,433	1,601,083	262,906	44,426	1,551	957
23	Commodity	4,024,066	91,714	2,157,270	2,248,984	308,518	635,828	382,058	445,795	2,520	363
24	Subtotal	$45,182,029	$4,462,684	$30,551,002	$35,013,686	$4,229,215	$3,785,884	$1,348,485	$791,332	$11,098	$2,329
	TOTAL GAS PLANT IN SERVICE										
25	Demand	$232,411,551	$5,583,529	$157,351,229	$162,934,758	$23,281,297	$28,706,363	$12,663,395	$4,669,320	$136,816	$19,603
26	Customer	269,388,147	38,775,874	192,836,166	231,612,040	25,133,096	10,580,208	1,722,576	321,964	12,530	5,733
27	Commodity	4,375,520	99,721	2,345,670	2,445,391	335,461	691,364	415,430	484,739	2,740	395
28	**GRAND SUBTOTAL**	$506,175,218	$44,459,124	$352,533,065	$396,992,189	$48,749,855	$39,977,935	$14,801,400	$5,476,022	$152,085	$25,731

New England Division
Cost of Service Study
Total Revenue Requirements

Line No.	Description	Total Company	Residential Non-Heating	Residential Heating	Total Residential	C&I Small	C&I Medium	C&I Large	C&I Extra-Lg.	NGV	Gas Lamps
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	I. PRODUCTION										
1	Demand	$587,553	$9,833	$324,667	$334,500	$48,906	$91,648	$55,727	$56,562	$182	$28
2	Customer	0	0	0	0	0	0	0	0	0	0
3	Commodity	0	0	0	0	0	0	0	0	0	0
4	Total	$587,553	$9,833	$324,667	$334,500	$48,906	$91,648	$55,727	$56,562	$182	$28
	II. STORAGE AND PROCESSING										
5	Demand	$1,957,227	$33,290	$1,095,427	$1,128,718	$164,941	$305,391	$183,375	$174,087	$621	$96
6	Customer	0	0	0	0	0	0	0	0	0	0
7	Commodity	0	0	0	0	0	0	0	0	0	0
8	Seasonal	0	0	0	0	0	0	0	0	0	0
9	Total	$1,957,227	$33,290	$1,095,427	$1,128,718	$164,941	$305,391	$183,375	$174,087	$621	$96
	III. TRANSMISSION										
10	Demand	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
11	Customer	0	0	0	0	0	0	0	0	0	0
12	Commodity	0	0	0	0	0	0	0	0	0	0
13	Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	IV. DISTRIBUTION										
14	Demand	$41,453,088	$585,773	$16,406,810	$16,992,583	$2,425,672	$2,973,327	$1,287,597	$432,808	$14,478	$2,070
15	Customer	70,017,509	8,813,381	48,038,419	56,851,800	5,610,088	2,946,849	518,880	92,324	2,732	216
16	Commodity	16,630,667	495,580	10,053,494	10,549,073	1,410,819	2,290,920	1,229,663	1,007,620	5,581	717
17	Total	$128,101,263	$9,894,733	$74,498,723	$84,393,456	$9,446,579	$8,211,095	$3,036,140	$1,532,753	$22,791	$3,003
	V. TOTAL REVENUE REQUIREMENTS										
18	Demand	$43,997,868	$628,896	$17,826,905	$18,455,800	$2,639,519	$3,370,365	$1,526,699	$663,457	$15,281	$2,194
19	Customer	70,017,509	8,813,381	48,038,419	56,851,800	5,610,088	2,946,849	518,880	92,324	2,732	216
20	Commodity	16,630,667	495,580	10,053,494	10,549,073	1,410,819	2,290,920	1,229,663	1,007,620	5,581	717
21	Total	$130,646,044	$9,937,856	$75,918,817	$85,856,673	$9,660,426	$8,608,134	$3,275,242	$1,763,402	$23,594	$3,127
	REALLOCATION OF NONTRADITIONAL NONTRADITIONAL REVENUE REQUIREMENTS										
22	Demand	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
23	Customer	0	0	0	0	0	0	0	0	0	0
24	Commodity	0	0	0	0	0	0	0	0	0	0
25	Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	TOTAL REALLOCATED REVENUE REQUIREMENTS										
26	Demand	$43,997,868	$628,896	$17,826,905	$18,455,800	$2,639,519	$3,370,365	$1,526,699	$663,457	$15,281	$2,194
27	Customer	70,017,509	8,813,381	48,038,419	56,851,800	5,610,088	2,946,849	518,880	92,324	2,732	216
28	Commodity	16,630,667	495,580	10,053,494	10,549,073	1,410,819	2,290,920	1,229,663	1,007,620	5,581	717
29	Total	$130,646,044	$9,937,856	$75,918,817	$85,856,673	$9,660,426	$8,608,134	$3,275,242	$1,763,402	$23,594	$3,127

New England Division
Cost of Service Study
Unit Cost Summary

Line No.	Description	Total Company	Residential Non-Heating	Residential Heating	Total Residential	C&I Small	C&I Medium	C&I Large	C&I Extra-Lg.	NGV	Gas Lamps
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	I. PRODUCTION										
1	Demand	$0.0176	$0.0129	$0.0181	$0.0179	$0.0191	$0.0174	$0.0176	$0.0153	$0.0087	$0.0093
2	Customer	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
3	Commodity	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
4	Total	$0.0176	$0.0129	$0.0181	$0.0179	$0.0191	$0.0174	$0.0176	$0.0153	$0.0087	$0.0093
	II. STORAGE AND PROCESSING										
5	Demand	$0.0586	$0.0438	$0.0612	$0.0605	$0.0644	$0.0579	$0.0578	$0.0470	$0.0297	$0.0317
6	Customer	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
7	Commodity	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
8	Total	$0.0586	$0.0438	$0.0612	$0.0605	$0.0644	$0.0579	$0.0578	$0.0470	$0.0297	$0.0317
	III. TRANSMISSION										
9	Demand	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
10	Customer	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
11	Commodity	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
12	Total	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
	IV. DISTRIBUTION										
13	Demand	$1.2412	$0.7699	$0.9165	$0.9105	$0.9474	$0.5634	$0.4060	$0.1170	$0.6921	$0.6873
14	Customer	2.0966	11.5835	2.6834	3.0462	2.1912	0.5584	0.1636	0.0249	0.1306	0.0718
15	Commodity	0.4980	0.6513	0.5616	0.5652	0.5510	0.4341	0.3878	0.2723	0.2668	0.2379
16	Total	$3.8358	$13.0047	$4.1614	$4.5219	$3.6897	$1.5560	$0.9574	$0.4142	$1.0895	$0.9970
	V. TOTAL REVENUE REQUIREMENTS										
17	Demand	$1.3174	$0.8266	$0.9958	$0.9889	$1.0309	$0.6387	$0.4814	$0.1793	$0.7305	$0.7284
18	Customer	2.0966	11.5835	2.6834	3.0462	2.1912	0.5584	0.1636	0.0249	0.1306	0.0718
19	Commodity	0.4980	0.6513	0.5616	0.5652	0.5510	0.4341	0.3878	0.2723	0.2668	0.2379
20	Total	$3.9120	$13.0614	$4.2407	$4.6003	$3.7732	$1.6312	$1.0328	$0.4765	$1.1279	$1.0381
21	Monthly Customer Charge	$24.41	$20.51	$22.24	$21.95	$25.37	$59.37	$89.90	$92.70	$37.95	$0.75
22	Monthly Demand Charge	$9.97	$9.62	$6.92	$6.99	$6.36	$5.05	$4.12	$2.07	$21.22	$22.85
23	Monthly Demand Charge	$9.97	$9.62	$6.92	$6.99	$6.36	$5.05	$4.12	$2.07	$21.22	$22.85

New England Division
Cost of Service Study
Monthly Customer Charge

Line No.	Description	Total Company	Residential Non-Heating	Residential Heating	Total Residential	C&I Small	C&I Medium	C&I Large	C&I Extra-Lg.	NGV	Gas Lamps
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**ADMINISTRATIVE & GENERAL**	5.90	5.58	5.49	5.50	7.15	18.49	26.12	25.71	12.48	1.90
	O & M COSTS										
2	Mains and Service Expenses-Services Portion	0.30	0.10	0.29	0.26	0.39	0.60	0.67	0.71	1.00	0.00
3	Meter and House Regulator Expenses	0.66	0.46	0.48	0.48	1.25	6.27	10.42	11.79	1.57	0.00
4	Customer Installation Expenses	1.11	1.17	1.07	1.09	1.20	1.99	2.66	0.60	4.29	0.00
5	Maintenance of Services	0.18	0.17	0.17	0.17	0.22	0.24	0.25	0.26	0.38	0.00
6	Maintenance of Meters and House Regulators	0.21	0.14	0.15	0.15	0.39	1.95	3.24	3.66	0.49	0.00
7	Maintenance of Industrial M&R Equipment	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8	Other Distribution	0.56	0.68	0.48	0.52	0.65	3.50	3.92	3.91	0.87	0.00
9	**DISTRIBUTION SUBTOTAL**	3.02	2.73	2.64	2.66	4.10	14.55	21.16	20.95	8.59	0.00
10	Meter Reading Expenses	0.15	0.14	0.16	0.16	0.16	0.13	0.16	0.26	0.05	0.00
11	Customer Records and Collection Expenses	2.16	2.16	2.16	2.16	2.16	2.16	2.16	2.16	2.16	2.16
12	Uncollectible Accounts - Customer Charge Portion	0.26	0.16	0.29	0.27	0.13	0.26	0.80	0.56	0.00	0.00
13	Miscellaneous Customer Accounts	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50
14	Other Customer Accounts	3.30	2.01	3.71	3.42	1.64	3.41	10.35	7.27	0.00	0.00
15	**CUSTOMER ACCOUNTS SUBTOTAL**	6.37	4.97	6.81	6.50	4.58	6.46	13.97	10.75	2.71	2.66
16	**CUSTOMER SERVICE**	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16
17	**SALES**	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.00	0.00
18	**POST TEST YEAR & OTHER**	0.59	0.52	0.58	0.57	0.61	1.51	2.33	2.19	0.91	0.18
19	Services, Meter, Meter Installation	3.66	3.44	3.42	3.43	4.78	9.40	13.24	14.34	7.51	0.00
20	House Regulators	0.01	0.01	0.01	0.01	0.01	0.01	0.13	0.45	0.00	0.00
21	House Regulator Installations	0.01	0.01	0.01	0.01	0.01	0.01	0.10	0.35	0.00	0.00
22	Industrial Measuring and Regulating Equipment	0.01	0.00	0.00	0.00	0.00	0.33	0.33	0.33	0.00	0.00
23	Other Property on Customer Premises	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
24	Other Depreciation	0.51	0.48	0.48	0.48	0.62	1.62	2.29	2.25	1.09	0.17
25	**DEPRECIATION SUBTOTAL**	4.19	3.94	3.92	3.92	5.42	11.37	16.08	17.72	8.61	0.17
26	OTHER TAXES	2.30	2.20	2.17	2.17	2.79	5.97	8.39	8.71	4.50	0.58
27	GROSS RECEIPTS TAXES	0.19	0.16	0.17	0.17	0.29	0.57	1.26	6.15	0.00	0.00
	RATE BASE RELATED (RETURN & FIT)										
28	Mains	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
29	Services	0.43	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
30	Meters, Meter Installations	0.57	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
31	House Regulators	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
32	House Regulator Installations	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
33	Industrial Measuring and Regulating Equipment	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
34	Other Property on Customer Premises	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
35	Other	0.38	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
36	**SUBTOTAL**	1.39	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
37	**TOTAL**	24.36	20.48	22.17	21.89	25.34	59.32	89.72	92.57	37.95	5.64

New England Division
Cost of Service Study
Total Revenue Requirements

Line No.	Description	Total Company	Residential Non-Heating	Residential Heating	Total Residential	C&I Small	C&I Medium	C&I Large	C&I Extra-Lg.	NGV	Gas Lamps
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	OPERATIONS AND MAINTENANCE EXPENSES										
1	Demand	$15,122,739	$360,759	$10,196,584	$10,557,343	$1,509,205	$1,880,076	$838,364	$327,686	$8,802	$1,263
2	Customer	$46,841,504	$6,106,610	$34,515,745	$40,622,355	$3,729,374	$2,057,798	$370,315	$59,872	$1,789	$0
3	Commodity	$6,317,371	$199,470	$3,608,328	$3,807,798	$510,779	$926,265	$533,434	$535,635	$3,033	$426
4	Total	$68,281,614	$6,666,839	$48,320,658	$54,987,497	$5,749,358	$4,864,139	$1,742,113	$923,194	$13,624	$1,688
	DEPRECIATION										
5	Demand	$6,123,180	$145,440	$4,118,200	$4,263,640	$609,673	$764,249	$343,001	$138,570	$3,539	$508
6	Customer	$12,030,266	$1,694,135	$8,460,957	$10,155,092	$1,199,482	$564,533	$92,840	$17,651	$620	$49
7	Commodity	$2,834,556	$64,581	$1,519,491	$1,584,071	$217,309	$447,908	$269,150	$314,087	$1,776	$256
8	Total	$20,988,002	$1,904,155	$14,098,648	$16,002,803	$2,026,464	$1,776,690	$704,990	$470,308	$5,934	$812
	TAXES OTHER THAN INCOME TAXES										
9	Demand	$4,700,577	$112,473	$3,174,976	$3,287,450	$469,858	$582,762	$258,678	$98,685	$2,749	$394
10	Customer	$6,601,781	$944,692	$4,686,468	$5,631,160	$616,627	$296,391	$48,433	$8,679	$324	$168
11	Commodity	$388,884	$8,863	$208,478	$217,341	$29,815	$61,446	$36,922	$43,082	$244	$35
12	Total	$11,691,242	$1,066,029	$8,069,922	$9,135,951	$1,116,300	$940,599	$344,033	$150,446	$3,317	$597
	GROSS RECEIPTS TAXES										
13	Demand	$119,552	$0	$0	$0	$5	$48,538	$29,310	$41,699	$0	$0
14	Customer	$549,338	$67,943	$375,249	$443,193	$64,604	$28,127	$7,292	$6,122	$0	$0
15	Commodity	$6,953,582	$222,666	$4,717,197	$4,939,863	$652,916	$855,300	$390,157	$114,817	$529	$0
16	Total	$7,622,472	$290,609	$5,092,446	$5,383,055	$717,525	$931,965	$426,760	$162,639	$529	$0
	RETURN										
17	Demand	$13,800,246	$7,868	$259,465	$267,333	$39,079	$72,912	$44,134	$43,725	$146	$23
18	Customer	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
19	Commodity	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
20	Total	$13,800,246	$7,868	$259,465	$267,333	$39,079	$72,912	$44,134	$43,725	$146	$23
	INCOME TAXES										
21	Demand	$4,131,575	$2,356	$77,680	$80,035	$11,700	$21,829	$13,213	$13,091	$44	$7
22	Customer	$3,994,620	$0	$0	$0	$0	$0	$0	$0	$0	$0
23	Commodity	$136,273	$0	$0	$0	$0	$0	$0	$0	$0	$0
24	Total	$8,262,468	$2,356	$77,680	$80,035	$11,700	$21,829	$13,213	$13,091	$44	$7
	TOTAL REVENUE REQUIREMENTS										
25	Demand	$43,997,868	$628,896	$17,826,905	$18,455,800	$2,639,519	$3,370,365	$1,526,699	$663,457	$15,281	$2,194
26	Customer	70,017,509	8,813,381	48,038,419	$56,851,800	5,610,088	2,946,849	518,880	92,324	$2,732	$216
27	Commodity	16,630,667	495,580	10,053,494	$10,549,073	1,410,819	2,290,920	1,229,663	1,007,620	$5,581	$717
28	Total	$130,646,044	$9,937,856	$75,918,817	$85,856,673	$9,660,426	$8,608,134	$3,275,242	$1,763,402	$23,594	$3,127

Data Request TEC-RI 1-90

Request:

Please provide, or identify the location in the filing of, the design day and design hour demand contributions by rate class.

Response:

Design day and design hour demands by rate class were not prepared for this rate case.

Prepared by or under the supervision of: David Heintz

Data Request TEC-RI 1-91

Request:

What allocation factor is used to allocate the new ARP capital program expenses to rate classes? How about the Gas Marketing Program expenses?

Response:

The expenses related to the ARP capital program were included in account 887, maintenance of mains, and allocated to the rate classes using the RSUM factor.

Gas Marketing Program expenses related to the residential program were allocated to the residential classes based on the number of expected heating and non-heating customers. The Gas Marketing Program expenses related to the C&I programs were allocated to the C&I classes based on the expected number of customers in those classes.

Prepared by or under the supervision of: David Heintz

Data Request TEC-RI 1-92

Request:

Will the DAC charge be set to zero starting October 1, 2008? If not, why not?

Response:

The DAC charge will not be set to zero starting October 1, 2008. The existing DAC components are continued in the Company's proposed tariff and most of those components, such as the environmental response cost and non-firm margin factors, are based on historic data that is still appropriately recovered/credited to customers with the approval of the proposed tariff. However, the new P&PBOP, CapX, and RDM components will be set to zero until the first annual DAC filing after the Commission's approval of the proposed tariff.

Prepared by or under the supervision of: Peter Czekanski

Data Request TEC-RI 1-93

Request:

Please provide the justification for splitting cost savings from AMR 50/50 between the Company and the ratepayer.

Response:

The Company is not proposing to split cost savings from AMR 50/50 between the Company and the ratepayer. The adjustment included in the Rate Year reflects the anticipation of savings to be realized during the Rate Year period and is consistent with the "average" rate base impact of the project investment in the Rate Year. As shown in Attachment NG-MDL-6, Page 3 of 9, at lines 14 and 15, the incremental 50% of AMR savings are included beginning in the second rate year.

Prepared by or under the supervision of: Mike Laflamme