**NORTHERN UTILITIES, INC.**
**NEW HAMPSHIRE DIVISION**
**WINTER PERIOD 2004-2005**
**COST OF GAS ADJUSTMENT FILING**
**PREFILED TESTIMONY OF**
**JOSEPH A. FERRO**

Q. Please state your name and business address.

A. Joseph A. Ferro, 300 Friberg Parkway, Westborough, Massachusetts 01581.

Q. What is your position with Northern Utilities, Inc. ("Northern" or the "Company")?

A. My position is Manager, Regulatory Policy.

Q. Please describe your educational background and utility experience.

A. I graduated from the University of Massachusetts/Boston in 1974 with a Bachelor of Arts degree in Mathematics. I later took accounting courses at Massasoit Community College. I have been employed at Bay State Gas Company ("Bay State") since 1977, holding various positions in the Customer Relations area before joining the Rate Department in September 1980 as an Associate Rate Analyst. In February 1983 I was promoted to Rate Analyst. In August 1987 I was promoted to Senior Rate Analyst. On February 1, 1990 I was promoted to Manager, Gas Costing and Rate Analysis; in 1994 I was promoted to Manager, Rate Services and on August 1, 1998 I was promoted to Director of Pricing Services. On August 16, 1999 I became Director, Revenue Development. Around the completion of the merger between NiSource, Inc. and Columbia Energy Group (around November 1, 2000) I was assigned the position of Manager, Regulatory Policy.

Q. What have been your primary responsibilities in the various positions that you have held in the Regulatory Affairs and Rate areas?

A. My primary responsibilities for Bay State and Northern throughout my years of service have included the preparation and support of Cost of Gas Adjustment ("CGA") filings, analyses and forecasting of rates and revenues, supporting adjustments to test year costs as well as determining and sponsoring revenues and billing determinants in Company rate case filings and other rate-related functions. As Director of Pricing Services and Director, Revenue Development, my responsibilities expanded to include directing the analysis and filing of rate design proposals including unbundling initiatives, analyzing the feasibility and filing of special rate contracts, administering all rate tariffs, as well as providing the Company with competitive pricing assessments and implementing effective pricing to enhance the Company's ability to retain and profitably grow distribution load. In my current position of Manager, Regulatory Policy, my responsibilities include setting regulatory and pricing policy and carrying out associated Company initiatives.

Q. Are you a member of any industry organizations?

A. Yes. I am a member of the Northeast Gas Association (formerly, New England Gas Association) Rates and Planning Group and a member of the American Gas Association Rates and Strategic Issues Committee.

Q. Have you previously testified before any regulatory bodies?

A. Yes. I have testified before the New Hampshire Public Utilities Commission ("Commission"), the Massachusetts Department of Telecommunications and Energy (formerly the Department of Public Utilities), and the Maine Public Utilities Commission.

Q. Please explain the purpose of your pre-filed direct testimony in this proceeding

A. The purpose of my testimony is to explain the calculation of the Unit Cost of Gas to be billed from November 1, 2004 to April 30, 2005. I will explain the derivations of the rates and capacity quantities used in the forecast by the Company's gas suppliers and upstream transporters, as well as the commodity volumes purchased during the winter period. I will further explain the sales forecast and resulting sendout forecast. I will also explain the derivations of interruptible credits, capacity release revenues and the proposed Local Delivery Adjustment Clause charge. Finally, I will describe the rate and typical bill impact resulting from the proposed COG rate change.

## COST OF GAS

Q. Would you please explain tariff page, Proposed Eleventh Revised 38 and Eleventh Revised Page 39?

A. Proposed Eleventh Revised Page 38 and Eleventh Revised Page 39 contain the calculation of the 2004-2005 Winter Unit Cost of Gas rate and summarizes the Company's forecast of gas sendout and gas costs. The estimated Total Anticipated Cost of Gas from November 1, 2004 to April 30, 2005 is $34,880,982,and includes the winter-related gas costs incurred during the summer period ("Summer Deferred') of $1,525,683 and the winter period forecast interruptible sales margins (credit) of $2,099.

The Gas Cost Section presents the November 2004 through April 2005 forecast commodity and capacity volumes and costs allocated to the New Hampshire division.

To derive the Total Anticipated Period Costs of $35,599,137 the following indirect cost of gas charges and credits (totaling $718,154) have been added to the $34,880,982 Total Anticipated Cost of Gas:

1.) Prior Period Over Collection- ($311,393).

2.) Interest Expense- $7,922.

3.) Working Capital Allowance- $69,484.

4.) Bad Debt Allowance- $168,234.

5.) Miscellaneous Overhead- $97,234.

6.) Production and Storage Capacity- $686,673.

The unit anticipated cost of gas adjustment of $0.9345 per therm is the sum of the anticipated direct cost of gas rate of $0.9156 per therm and the anticipated indirect cost of gas rate of $0.0189 per therm. The direct and indirect cost of gas rates were determined using the forecasted firm sales volumes of 38,094,890 therms. This unit cost of gas of $0.9345 per therm becomes the COG rate for the residential class customers. The commercial and industrial low winter rate classes (G-50, G-51, G-52) are assigned a COG rate of $0.6736 per therm, which is based on the unit cost of gas times the low winter classes' gas cost ratio of 0.72633 and then adjusted by a correction factor of 0.9924 to balance to the upcoming period gas costs intended to be recovered. Similarly, the commercial and industrial high winter rate classes (G-40, G-41, G-42) are assigned a COG rate of $0.9978 per therm by applying the gas cost ratio of 1.07588 and then adjusted for the same correction factor of 0.9924. The gas cost ratios used to derive load factor based COGs for the commercial and industrial classes resulted from a settlement approved by the Commission in the Company's rate redesign case, Docket DG 00-046. The derivation of the correction factor is in the Allocation Section.

Q. Please explain the basis for allocating the fixed, capacity-related demand costs between the New Hampshire and Maine divisions of Northern Utilities.

A. The fixed, capacity-related demand costs are allocated between the Company's two divisions on the basis of Proportional Responsibility ("PR") factors. The PR allocation method looks to a design year for the 12-month period ending April 30, and assigns Northern's projected annual demand costs to the individual months on the basis of the peak demand of each month during the design year, and then allocates the resulting assigned monthly demand costs to each division on the basis of the design year's monthly firm sendout factors. This method for allocating fixed demand costs was approved by the Commission in the 1995-96 Winter COG proceeding, Docket DG 95-257. The PR allocation is established for the year beginning with the Company's upcoming winter period COG. The workpapers used to develop the PR factors in the winter 2004-2005 COG are included in the Allocation Section.

Q. What is the basis for allocating the variable gas costs between Northern's New Hampshire and Maine divisions?

A. The variable gas costs have been allocated between the New Hampshire and Maine divisions of Northern on the basis of each division's percentage of monthly firm sendout. The monthly variable allocation factors are shown on the first page of the Allocation Section.

## PRIOR PERIOD UNDERCOLLECTION

Q. Please explain the prior Winter Period over- collection of $311,393 shown on Eleventh Revised Page 39?

A. The reconciliation analysis that was filed with the Commission on July 26, 2004, and included in the Reconciliation Section of this filing, provides the explanation and support of a $321,777 over-collection through May 2004.

Q. Please explain the difference of $10,384 between the balance of $321,777, reported in the July 26, 2004 filing, and the $311,393 over-collection incorporated in the COG calculation on Eleventh Revised Page 39.

A. Prior to the start of the 2003 winter period gas cost audit conducted jointly by the New Hampshire commission audit staff and the Maine commission staff at Northern's Westborough, MA office on August 17-18, 2004, it was discovered that several adjustments to inventory interest had not been correctly reflected in the reconciliation filed with the Commission. These adjustments increased commodity gas costs by $4,641 and interest on the over/under balances by $100, thus reducing the over collection by $4,741. Also, reflected in the revised balance are the May 2004 through October 2004 interruptible sales margins totaling $3,468, which reflect actual margins for May and June 2004 and forecast margins for July through October 2004. Finally, due to these cost changes, accumulated interest expense through the summer period associated with winter period costs has increased, resulting in a further reduction in the over-collection by $9,111.

In addition to impacting the over-collected direct gas cost balance, these revisions impacted (increased) the working capital allowance by $9 and bad debt expense by $21.

Q. Has the Company provided supporting schedules for these revisions?

A. Yes. All reconciliation schedules affected by these revisions are included in the Reconciliation Section of this filing and have been placed after the complete July 26, 2004 reconciliation filing. In addition, the Company provided the revised inventory interest and pertinent back-up schedules to the Audit Staff at the audit at the Company's office. With respect to the interruptible sales margins, a schedule in the Interruptible Exhibits Section shows the annual interruptible sales margins totaling $5,535, of which the $3,435 is for the months of May through October 2004, and $2,099 pertains to the months of November 2004 through April 2005.

Q. Mr. Ferro, is the Company planning any changes in administering interruptible sales service during the upcoming winter period?

A. Yes, the Company has recently notified all its interruptible sales customers, via a direct mailing of a letter signed by Northern's President, Stephen H. Bryant, a copy of which was provided to Commission Staff, that it will be more formally and distinctly curtailing interruptible gas service from December 1, 2004 through March 31, 2005. This curtailment period will be enforced by turning off each customer's meter, and by doing so will avoid any compromising of the Company's ability to provide reliable gas supply and distribution service to its firm customers. Such action will also avoid any potential cost impact to firm customers resulting from any contractual restrictions in charging interruptible sales customers for the unauthorized use of gas at a rate that clears the daily marginal cost of gas supply delivered to Northern's city-gate.

Q. If the Company plans on curtailing interruptible service from December 1, 2004 through March 31, 2005, why is the Company forecasting interruptible profits in December 2004 and March 2005 as shown in the Interruptible Profits Section?

A. At the time the Company prepared its sales and sendout forecast, the Company had not yet decided to implement its more formal curtailment process, and it would have been time consuming and impractical to re-run its dispatch to reflect this change, especially considering that the total interruptible sales profits for the months of December and March reflected in the filing is only $1,097, an amount that is too small to impact the COG. Moreover, all non-firm margins (interruptible sales and capacity release revenues) will be reconciled after the Winter 2004-05 COG period is closed next year.

## FORECASTED SUPPLIER RATES AND COMMODITY COSTS

Q. Please explain the basis for projecting costs for the purchases of Canadian gas supplies.

A. Northern has firm entitlements of up to approximately 4,400 Dth/day of year-round Canadian supplies from Granite State Gas Transmission ("Granite State") under Granite State's Rate Schedules CS-F and CS-RG, and directly from EnCana and Husky. The pricing provisions of the agreements that Northern has entered into with Granite State for the purchase of Canadian supplies from Direct Energy Marketing and ProGas, Ltd. mirror the underlying provisions contained in the contracts that Granite State has with these suppliers. Granite State assigned proportionately all of its rights to the Boundary Gas contract to its customers when it restructured in accordance with Order No. 636. The provisions contained in the assigned Boundary Gas (now EnCana) contract remain the same as when Granite State was the purchasing party to such contract. Commodity prices for Direct Energy Marketing supplies are forecasted based on NYMEX prices from September 2, 2004, plus or minus a differential based on the U.S. border price, plus the upstream transportation costs to get the gas to Granite State's pipeline. The forecasted price of EnCana was based on the September 2, 2004 NYMEX prices plus a differential. Domestic supplies are forecasted based on NYMEX prices from September 2, 2004, plus the cost to transport the gas to the city gate.

The forecast of product demand costs from EnCana and Husky are based on the most recent month's invoice price. Product demand costs for Direct Energy Marketing are $0.50 per Dth, which mirrors Granite State's contracts. Product demand MDQs are shown in the Gas Cost Section.

Q. Please explain the basis for the projected costs of the Company's domestic gas supply purchases.

A. The Company will be purchasing all of its domestic requirements on the spot market during the upcoming Winter Period. The commodity forecast for domestic supplies relies on monthly gas indices for which the NYMEX Natural Gas Futures prices of September 2, 2003 were used. The transportation costs are forecasted based on the route the sendout model chooses that the gas will travel. The sendout model provides the forecasted MMBtus transported on each of the upstream pipelines. The sendout on each pipeline is then multiplied by the appropriate upstream commodity costs and added to the monthly gas indices.

Q. Mr. Ferro, how has the Company reflected the results of its hedging activity for the upcoming winter period months in the COG calculation?

A. The schedule in the Hedging Section shows the gains and losses resulting from the entry price position versus the forecasted NYMEX prices for each month of November 2004 through October 2005. The net gain of ($292,585) results in all hedged gas volumes during the upcoming winter period to be at the cost of the entry prices of the hedged positions. This gain or credit to commodity costs is also shown on the tariff sheet, Eleventh Revised Page 38.

## FORECASTED TRANSPORTATION COSTS

Q. Please explain the basis for the Company's forecasted pipeline reservation and commodity charges for transportation services included in this COG filing.

A. Northern currently has entitlement to firm transportation capacity on eleven (11) interstate pipeline companies: Tennessee Gas Pipeline Company, Iroquois Gas Transmission System, Algonquin Gas Transmission Company, Texas Eastern Transmission Corporation, Transcontinental Gas Pipe Line Company, Dominion Transmission Corporation, National Fuel Gas Supply Corporation, Texas Gas Transmission Corporation, Granite State, TransCanada Pipeline and Portland Natural Gas Transmission System. The Suppliers Prices Section reflects the maximum daily transportation quantity (MDTQ) of firm capacity that Northern has with each of the above pipelines. As an interstate pipeline, each pipeline is regulated by the Federal Energy Regulatory Commission ("FERC") and is required to file tariffs reflecting its rates for transportation services. For purposes of forecasting pipeline reservation and commodity charges, the rates reflected on each pipeline's currently effective tariff sheets have been applied to the applicable contracted MDTQ and to the forecasted transportation quantities.

The Suppliers Price Section contains the currently effective pipeline tariff sheets, while the Gas Cost Section provides the summary of the pipeline reservation and product demand charges allocated to the New Hampshire division.

Q. What firm capacity, or MDTQ, does the Company plan to contract for with Granite State for the upcoming annual period beginning November 1, 2004?

A. As indicated in Mr. DaFonte's testimony, the Company is planning to contract for 100,000 Dth a day from Granite State for the annual period November 1, 2004 through October 31, 2005. This MDTQ is presented in the Supplier Prices Section; the sum of all Granite State FT-NN contract quantities equals 100,000 Dth.

## OTHER SUPPLY COSTS

Q. Please explain how you estimated the LNG rate for the Winter Period.

A. The LNG rate shown in the Gas Cost Section, of $7.5385 per MMBtu, is the estimated average cost of LNG withdrawn from inventory between November 1, 2004 and April 30, 2005.

Q. Please explain how you estimated the propane rate for the Winter 2004-2005 period.

A. The propane rate of $7.8539 per MMBtu shown in the Supplier Prices Section, is the average cost of forecasted propane sendout between November 1, 2004 and April 30, 2005. The cost of propane put into inventory, including transportation is forecasted at $7.79 per MMBtu. The derivation of the average cost of propane and the corresponding forecasted inventory activity is presented in the Inventories Section.

Q. Please explain how you estimated the FS-MA Storage rate for the Winter 2004-2005 period.

A. The rate for FS-MA storage withdrawals, (storage component of former SS-NE) of

$5.4498 per MMBtu, as shown in the Supplier Prices Section, is the average cost of FS-MA storage gas withdrawn from inventory and used for processing between November 1, 2004 and April 30, 2005. The cost of injections into inventory is at the estimated weighted average costs of incremental domestic supplies plus the $0.0102 per MMBtu Tennessee injection charge. The derivation of the average cost of FS-MA Storage is shown in the Inventories Section. Withdrawal and processing volumes are forecasted for the period November 1, 2004 through April 30, 2005.

Q. Please explain how you estimated the Texas Eastern SS-1 Storage rate for Winter 2004-2005 period.

A. The rate for Texas Eastern (TETCO) SS-1 storage withdrawals of $3.9066 per MMBtu, as shown in the Supplier Prices Section, is the average cost of TGP SS-1 storage gas withdrawn from inventory and used for processing between November 1, 2004 and April 30, 2005. The cost of injections into inventory is at the estimated weighted average costs of incremental domestic supplies plus the $0.04 per MMBtu TGP injection charge. The derivation of the average cost of TETCO SS-1 Storage is shown in the Inventories Section. Withdrawal and processing volumes are forecasted for the period November 1, 2004 through April 30, 2005.

Q. Please explain how you estimated the Texas Eastern FSS-1 Storage rate for Winter 2004-2005 period.

A. The rate for Texas Eastern FSS-1 storage withdrawals of $4.9966 per MMBtu, as shown in the Supplier Prices Section, is the average cost of Texas Eastern FSS-1 storage gas withdrawn from inventory and used for processing between November 1, 2004 and April 30, 2005. The cost of injections into inventory is at the estimated weighted average costs of incremental domestic supplies plus the $0.04 per MMBtu Texas Eastern FSS-1 injection charge. The derivation of the average cost of Texas Eastern FSS-1 Storage is shown in the Inventories Section. Withdrawal and processing volumes are forecasted for the period November 1, 2004 through April 30, 2005.

Q. Please explain how you estimated the MCN Storage rate for Winter 2004-2005 period.

A. The rate for MCN storage withdrawals of $5.5283 per MMBtu, as shown in the Supplier Prices Section, is the average cost of MCN storage gas withdrawn from inventory and used for processing between November 1, 2004 and April 30, 2005. The derivation of the average cost of MCN Storage is shown in the Inventories Section. Withdrawal and processing volumes are forecasted for the period November 1, 2004 through April 30, 2005.

Q. Will the Company propose to revise the COG if it receives any new or updated information on supplier or transportation rates?

A. Yes. If the Company receives more accurate information on Northern's forecasted supplier/transportation rates, it will assess whether a revised COG proposal is warranted. If the different rate information materially changes the proposed COG and if time permits before the hearing date, the Company will then notify all parties to this proceeding and file a revised proposed COG bearing an effective date of November 1, 2004

## SALES AND SENDOUT FORECAST

Q. Please compare forecasted sales for the COG period with normalized sales for the same period last year.

A. Total sales for the COG period are projected to increase by 1.2% with the residential class increasing by 1.7% and the C&I class by increasing by 0.8%. The increases are driven mainly by customer growth.

Q. How does the Company forecast firm sales and transportation?

A. For the residential and small commercial forecasts, the Company relies upon econometric and time-series techniques for two components: use per meter and the number of meters. Individual forecasts are made for large commercial customers with special contracts. These models forecast total throughput with sales and transportation allocated according to the most recent twelve months of data. Trends in transportation and known switches between sales service and transportation service are incorporated where appropriate.

Q. How does the Company forecast firm sendout?

A. The firm sales and transportation forecast serves as the basis of the sendout forecast. Calendar month firm sales and transportation are converted to a forecast of sendout by applying an unaccounted-for conversion factor that is the average of the most recent four (4) years ending June 30. The unaccounted-for factor reflects the same data that the Company has filed with DOT for each of those four years.

## LOCAL DELIVERY ADJUSTMENT CLAUSE

## ENVIRONMENTAL RESPONSE COSTS

Q Would you please explain the Environmental Response Costs ("ERC") rate reflected on

Proposed Page 56?

A. During the period July 1, 2003 through June 30, 2004, ERC expenses totaled $291,630. The Company is allowed to recover one-seventh of the actual response costs incurred by the Company in a calendar year until fully amortized plus any insurance and third-party expenses for the calendar year. Any insurance and third-party recoveries for the calendar year are then used to reduce the out-years of the amortization schedule. The $571,941 presented on Schedule 1 of the ERC Section is one-seventh of the ERC costs incurred through June 2004 of $41,661, plus the 2002-2003 amount of $31,946 plus the 2001-2002 amount of $147,916 and the 2000-2001 amount of $328,823. The prior period reconciliation of ERC costs, an under-collection of $21,909, as well as a credit of ($314) from the 2003 audit of ERC costs, is applied to the annual ERC costs resulting in total ERC costs to be recovered from customers in the period of November 2004 through October 2005 of $571,941. Dividing these recoverable ERC costs by estimated total annual throughput volumes of 54,406,766 therms, yields an ERC rate of $0.0105 per therm. This ERC rate is included in the LDAC rate on Proposed Seventh Revised Page 56.

## WELLS SURCHARGE

Q. Please explain the derivation of the Wells Surcharge.

A. Pursuant to a joint stipulation and agreement dated September 3, 1999 in FERC Docket No. CP99-238-000 and CP96-610-000, between Granite State, Northern, the Maine Public Utilities Commission, the New Hampshire Public Utilities Commission, the Staff of the NHPUC, the Maine Public Advocate, the New Hampshire Consumer Advocate and No

Tanks, Inc., Granite State is to charge Northern $6.95 million plus carrying costs for a total of $8,342,241 over a seven-year period. The Wells Surcharge schedule reflects the annual recovery of $325,076, or $27,090 a month, plus interest, plus the prior year's under-recovery amount of $12,387 by Granite State (as compared to its scheduled recoveries) over the twelve-month period of November 2004 through October 2005. The Wells Surcharge of $0.0068 per therm is included in the LDAC rate on Proposed Seventh Revised Page 56.

Q. Are there any other changes to the LDAC rates shown on Seventh Revised Page No. 56?

A. Yes. The Rate Case Expense (RCE) LDAC component is scheduled to expire on October 31, 2004. At that time, the RCE will be reconciled and any remaining balance should be included in the next summer period COG filing.

Q. Please explain the source of the Demand Side Management Conservation Charges set out on Proposed Seventh Revised Page No. 56.

A. The Company implemented the Demand Side Management Conservation Charges ("DSM CC") with its Summer 2003 COG in connection with the Energy Efficiency Programs for Gas Utilities, DG 02-106, and pursuant to Order No. 24,109 issued on December 31, 2002. The DSM CCs are designed to recover Year Two Energy Efficiency costs over the 12-month period of November 2004 through October 2005. The Year Two Residential class CC rate will be $0.0003 per therm, while the CC rate for all commercial and industrial (C&I) classes will be ($0.0058) per therm.

**COG RATE AND BILL COMPARISON ANALYSES**

Q. How does the proposed 2004-2005 Winter COG rate compare with the actual 2003-2004 Winter COG rate?

A. The schedule in the Variance Analysis Section shows that the difference between the proposed 2004-2005 Winter rate and the average actual cost of gas in the 2003-2004 Winter period to be a decrease of $0.0595 per therm. Of this decrease, $0.0920 per therm can be attributed to a decrease in the over/under collection balance; a current $311,393 over-collection as compared to a previous $3,072,448 under-collection. An offset to these decreases is a $0.0156 per therm increase in the forecast of commodity prices, a $0.0102 increase due to the difference in the refund credit and a $0.0086 per therm increase in forecasted demand costs.

Q. How does the proposed COG rate affect a typical Residential Heating customer's annual and Winter Period bills for the twelve-month and six-month period ended April 2005 compared with the twelve-month and six-month period ended April 2004?

A. The Typical Bill analysis Section shows that a typical Residential Heating customer's bill for the six months ended April 2005, compared to the six months ended April 2004, will decrease by $35 or 2.7 percent based on typical winter consumption of 932 therms. For the twelve-month period ended April 2005, typical Residential Heating customers can expect to see an increase of $14 or 0.8%. These calculations used the forecasted winter 2004-2005 COG rate of $0.9345 per therm and the summer 2004 actual COG rates for the "current" period and the actual winter 2003-2004 and summer 2003 COG rates for the "previous" period. The Typical Bill Analysis Section shows that a residential heating customer using 30 therms per month will experience a decrease of $2.60 in the monthly bill or a 5% decrease and a customer who uses 200 therms will experience a $17.31 decrease, which translates to a 5% decrease.

## SUPPLIER BALANCING CHARGE, PEAKING SERVICE DEMAND CHARGE AND CAPACITY ALLOCATORS

Q. Mr. Ferro, how is the Company filing with the Commission its Supplier Balancing Charge, Peaking Service Demand Charge and Capacity Allocators for the upcoming winter period?

A. Under separate letter dated September 14, 2004, the Company is filing its revised Supplier Balancing Charge, Peaking Service Demand Charge and Capacity Allocators for the upcoming winter period. In this filing the Company explains the derivation of the charges and allocators and presents its revised Appendix A, Fourth Revised Page 154, and Appendix C, Third Revised Page 169, to Northern's Delivery Service Terms and Conditions, bearing an effective date of November 1, 2004. The Company is filing these revised charges and allocators in accordance with Commission directive to update them once a year, effective for the billing (calendar) month of November. It is the Company's understanding that this separate filing will be incorporated into this Winter 2004-2005 COG proceeding.

Q. Does this conclude your testimony?

A. Yes it does.