Exhibit Northern-1

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION
WINTER PERIOD 2007-2008
COST OF GAS ADJUSTMENT FILING
PREFILED TESTIMONY OF
RONALD D. GIBBONS

Q. Please state your name and business address.

A. Ronald D. Gibbons, 200 Civic Center Drive, Columbus, Ohio 43215.

Q. By whom are you employed?

A. I am employed by NiSource Corporate Services Company ("NCSC"), a management and services subsidiary of NiSource Inc. ("NiSource") and affiliate of Northern Utilities, Inc. ("Northern").

Q. What positions have you held during your employment with NiSource and its predecessors?

A. Since my employment in January 1981 by the Columbia Gas System Service Corporation, the predecessor of NCSC, I have held positions of increasing responsibility in the accounting department (1981-1984), as an auditor (1984-1989), and in the regulatory accounting department (1989-present). I was promoted to my present position, Manager of Regulatory Accounting, in May 2006.

Q. What are your present duties and responsibilities as Manager of Regulatory Accounting?

A. Since the merger of Columbia Energy Group and NiSource in November 2000, I have been responsible for coordinating and preparing data and reports required to support the recovery of gas costs as well as assisting in the preparation of rate case data and exhibits for Northern. In my current position as Manager, my responsibilities have increased to include all regulatory accounting activities for Northern, Bay State Gas Company ("Bay State") and Columbia Gas of Maryland. In the past, my work has included gas cost recovery activities and filings for Northern's affiliates Columbia Gas of Kentucky, Columbia Gas of Maryland, Columbia Gas of Pennsylvania and Columbia Gas of Virginia. I also assist the Director of Regulatory Services on various types of regulatory activities.

Q. What is your educational background?

A. I graduated from The Ohio State University in 1980 with a Bachelor of Science degree in Administrative Science. My major was accounting. I have also attended several ratemaking seminars sponsored by universities and trade associations.

Q. Have you previously testified before any regulatory bodies?

A. Yes. I have testified before the Public Service Commission of Kentucky, the Public Service Commission of Maryland, the Maine Public Utilities Commission ("MPUC" or "the Commission") and the New Hampshire Public Utilities Commission ("NHPUC").

Q. Please explain the purpose of your prepared direct testimony in this proceeding.

A. The purpose of my testimony is to explain the calculation of the Cost of Gas Factor (CGF) proposed to be billed by Northern from November 1, 2007 to April 30, 2008. I will explain the derivations of the rates used in the forecast by the Company's gas suppliers and upstream transporters. I will also explain the forecast of sales and resulting sendout requirements for the 2007-2008 Peak (or winter) period. In addition, I have incorporated the prior period over-collection filing in my testimony. I justify the inclusion in the overall reconciled costs of certain capacity costs resulting from the Settlements in Docket Nos. 2005-87 and 2005-273, by citing Commission approval of those Settlements. Finally, I present the impact that the proposed CGF will have on the bills of the Company's typical customers.

COST OF GAS

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

A. Proposed Revised Page 38 and Proposed Revised Page 39 contain the calculation of the 2007-2008 Winter Unit Cost of Gas and summarizes the Company's forecast of gas sendout and gas costs. The estimated Total Anticipated Direct Cost of Gas from November 1, 200 to April 30, 2008 is $39,969,615.

The Gas Cost Section presents the forecast commodity and capacity volumes and costs allocated to the New Hampshire division.

To derive the Total Anticipated Period Costs of $38,124,690 the following indirect gas costs and credits (totaling $1,844,926) have been added to the $39,969,615 Total Anticipated Direct Cost of Gas:

1.) Prior Period Over Collection- $2,770,024.
2.) Interest Expense- ($61,976).
3.) Working Capital Allowance- $65,404.

4.) Bad Debt Allowance- $159,879.

5.) Miscellaneous Overhead- $95,413.

Production and Storage Capacity- $686,673.

Refunds- ($20,394).

The unit anticipated cost of gas adjustment of $1.0415 per therm is the sum of the anticipated direct cost of gas rate of $1.0990 per therm and the anticipated indirect cost of gas rate of ($0.0575) per therm. The direct and indirect costs of gas rates were determined using the forecasted firm sales volumes of 32,095,060 therms. This unit cost of gas of $1.0415 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 $0.9661 per therm and the commercial and industrial high winter rate classes (G-40, G-41, G-42) are assigned a COG rate of $1.1442 per therm.

PROPORTIONAL RESPONSIBILITY (PR) ALLOCATION OF DEMAND COSTS

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

A. These costs are allocated between the divisions based on the Modified Proportional Responsibility ("MPR") methodology, which allocates the fixed capacity-related gas costs based on the demand each division places on the available capacity each month. The MPR methodology was approved by the Commission on December 23, 2005, effective January 1, 2006, pursuant to the Commission-approved Settlements in Docket Nos. 2005-077 and 2005-273. Accordingly, the MPR method was used to establish the proportional cost responsibility of Northern's Maine Division and Northern's New Hampshire Division. The workpapers supporting the MPR factors reflect the settlement reached in Docket Nos. 2005-077 and 2005-473 and are provided in the Allocation Exhibits 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 Utilities, Inc. on the basis of each division's percentage of monthly firm sendout. The monthly variable allocation factors are shown in the Allocation Section.

PRIOR PERIOD UNDERCOLLECTION

Q. Please explain the prior Winter Period under-collection of ($2,770,024) shown on Proposed Revised Page 39?

A. The reconciliation analysis that was filed with the Commission on July 31, 2007 of ($2,658,460) is being further reduced by carrying costs of ($111,564) on the balance through October 2007.

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 2,400 Dth/day of year-round Canadian supplies directly from Northeast Gas Marketing (NEGM). The forecasted price of NEGM was based on the August 31, 2007 NYMEX prices plus a differential. Domestic supplies are forecasted based on NYMEX prices from August 31, 2007, plus the cost to transport the gas to the city gate.

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

The Company will purchase all of its domestic supply on a short-term (monthly, daily) basis for the Peak Period. The commodity forecast for domestic supplies rely on monthly gas indices for which the NYMEX Natural Gas Futures prices of August 31, 2007 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 unit commodity costs and added to the monthly gas indices.

R. 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 a short-term (monthly, daily) basis for the upcoming Winter Period. The commodity forecast for domestic supplies relies on monthly gas indices for which the NYMEX Natural Gas Futures prices of August 31, 2007 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. Gibbons, 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 2007 through October 2008. The negative net position of $724,151 results in all hedged gas volumes during the upcoming winter period to be at the cost of the entry prices of the hedged positions. The gain is then allocated based on the same estimated commodity costs allocation between New Hampshire and Maine as the other commodity gas costs are allocated This positive or negative position amount as it relates to commodity costs is also shown on the tariff sheet, Proposed 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 Utilities currently has entitlement to firm transportation capacity on nine (9) interstate pipeline companies: Tennessee Gas Pipeline Company, Iroquois Gas Transmission System, Algonquin Gas Transmission Company, Texas Eastern Transmission Corporation, Granite State Gas Transmission, Inc, TransCanada Pipeline, Union Gas, Vector 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 Company 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, with the exception of Granite State reservation charges. Granite State reservation charges are in accordance with a negotiated contract between Granite State and Northern, for the five-year term of November 1, 2003 through

October 31, 2008, for an MDTQ of 100,000 Dth at the discounted monthly rate of $1.2639 per Dth. This contract was approved by the Commission in Docket No. 2003-762.

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

<u>OTHER SUPPLY COSTS</u>

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

A. The LNG rate of approximately $7.64 per MMBtu shown in the Inventories Section, is the estimated average cost of LNG withdrawn from inventory between November 1, 2007 and October 31, 2008. This average rate is also a function of the current actual inventory balance (volumes and costs) and the projected receipts of LNG prior to November 1, 2007.

Q. Please explain how you estimated the propane rate for the 2007-2008 Peak Period.

A. The propane rate of approximately $8.2642 per MMBtu shown in the Inventories Section is the average cost of forecasted propane sendout between November 1, 2007 and April 30, 2008. The cost of propane put into inventory, including transportation is forecasted at $8.49 per MMBtu, based on an $0.76 per gallon price of propane.

Q. Please explain how you estimated the FS-MA Storage rate for the 2007-2008 Peak Period.

A. The rate for FS-MA storage withdrawals, (storage component of former SS-NE) of $7.1357 per MMBtu, as shown in the Inventories Section, is the average cost of FS-MA storage gas withdrawn from inventory and used for processing between November 1, 2007 and April 30, 2008. The cost of injections into inventory is at the estimated weighted average costs of incremental domestic supplies plus the Tennessee injection charge. The average withdrawal cost is also a function of the actual average cost of inventory as of July 1, 2007. Withdrawal and processing volumes are forecasted for the period November 1, 2007 through April 30, 2008.

Q. Please explain how you estimated the Texas Eastern SS-1 Storage rate for peak 2007-2008 period.

A. The rate for Texas Eastern SS-1 storage withdrawals of $7.368 per MMBtu, as shown in the Inventories Section, is the average cost of Texas Eastern SS-1 storage gas withdrawn from inventory and used for processing between November 1, 2007 and April 30, 2008. The cost of injections into inventory is at the estimated weighted average costs of incremental domestic supplies plus the Texas Eastern injection charge. The average withdrawal cost is also a function of the actual average cost of inventory as of July 1, 2007. Withdrawal and processing volumes are forecasted for the period November 1, 2007 through April 30, 2008.

Q. Please explain how you estimated the Texas Eastern FSS-1 Storage rate for peak 2007-2008 period.

A. The rate for Texas Eastern FSS-1 storage withdrawals of $8.438 per MMBtu, as shown in the Inventories Section, is the average cost of Texas Eastern FSS-1 storage gas withdrawn from inventory and used for processing between November 1, 2007 and April 30, 2008. The cost of injections into inventory is at the estimated weighted average costs of incremental domestic supplies plus the Texas Eastern FSS-1 injection charge. The average withdrawal cost is also a function of the actual average cost of inventory as of July 1, 2007. Withdrawal and processing volumes are forecasted for the period November 1, 2007 through April 30, 2008.

Q. Please explain how you estimated the MCN Storage rate for peak 2007-2008 period.

A. The rate for MCN storage withdrawals of $6.74 per MMBtu, as shown in the Inventories Section, is the average cost of MCN storage gas withdrawn from inventory and used for processing between November 1, 2007 and April 30, 2008. The average withdrawal cost is also a function of the actual average cost of inventory as of July 1, 2007. Withdrawal and processing volumes are forecasted for the period November 1, 2007 through April 30, 2008.

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 notify all parties to this proceeding and will propose to revise the COG if the change is material and if all parties will have sufficient time to review the proposed change before the effective date of November 1, 2007.

SALES AND SENDOUT FORECAST

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

A. Sales for the COG period are projected to increase by 0.5% for the residential class and 1.2% for C&I. The increases are driven mainly by customer growth, with the residential growth rate reduced by projected conservation.

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. The growth rates for customers and volume from these models are applied to the most recent data normalized for weather.

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 is converted to a forecast of sendout by applying an unaccounted-for conversion factor that is the average of the most recent four 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 rate reflected on Proposed Page 56?

A. During the period July 1, 2006 through June 30, 2007, ERC expenses totaled $320,684. 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 $320,684 presented on Schedule 1 of the ERC Section is one-seventh of the ERC costs incurred through June 2007 of $26,656, plus the 2005-2006 amount of $90,352, plus the 2004-2005 amount of $129,871, plus the 2003-2004 amount of $41,661 and the 2002-2003 amount of $31,946.. The prior period reconciliation of ERC costs, an under-collection of $27,641 is applied to the annual ERC costs resulting in total ERC costs to be recovered from customers in the period of November 2007 through October 2008 of $348,325. Dividing these recoverable ERC costs by estimated total annual throughput volumes of 63,542,670 therms, yields an ERC rate of $0.0055 per therm. This ERC rate is included in the LDAC rate on Proposed Revised Page 56.

<u>DEMAND SIDE MANAGEMENT CONSERVATION CHARGE</u>

Q. Please explain the source of the Demand Side Management Conservation Charges set out on Proposed 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 Four Energy Efficiency costs over the 12-month period of November 2007 through October 2008. The Year Three Residential class CC rate will be $0.0122 per therm while the CC rate for all commercial and industrial (C&I)

classes will be $0.0066 per therm.

COG RATE AND BILL COMPARISON ANALYSES

Q. How does the proposed 2007-2008 Winter COG rate compare with the actual 2006-2007 Winter COG rate?

A. The schedule in the Variance Analysis Section shows that the difference between the proposed 2007-2008 Winter rate and the average actual cost of gas in the 2006-2007 Winter period to be a decrease of $0.2241 per therm. Of this decrease, $0.1270 per therm can be attributed to a decrease in commodity costs partially off-set by an increase of $0.0951 in demand costs. Contributing to the over all decrease is a decrease of $0.1440 in the over/under collection balance.

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 2008 compared with the twelve-month and six-month period ended April 2007?

A. The Typical Bill analysis Section shows that a typical Residential Heating customer's bill for the six months ended April 2008, compared to the six months ended April 2007, will decrease by $290 or 17.5 percent based on typical winter consumption of 932 therms. For the twelve-month period ended April 2008, typical Residential Heating customers can expect to see an decrease of $328 or 15.3%. These calculations used the forecasted winter 2007-2008 COG rate of $1.0480 per therm and the summer 2007 actual COG rates for the "current" period and the actual winter 2006-2007 and summer 2006 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 $4.55 in the monthly bill or a 10% decrease and a customer who uses 200 therms will experience a $45.50 decrease, which translates to a 14% increase.

SUPPLIER BALANCING CHARGE, PEAKING SERVICE DEMAND CHARGE AND CAPACITY ALLOCATORS

Q. Mr. Gibbons, 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. As part of this filing, 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, Seventh Revised Page 154, and Appendix C, Sixth Revised Page 169, to Northern's Delivery Service Terms and Conditions, bearing an effective date of November 1, 2005. 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. The Company has incorporated this filing into this Winter 2006-2007 COG proceeding by including it in a Supplier Charges section.

Q. Is the Company submitting any other information with this cost of gas filing?

A. Yes, we are. The Company is taking this opportunity to file its annual Re-Enry Fee report and calculation. The filed information shows that the revised Unit Capacity Cost for re-Entry Fee to be $267.44.

Q. Did any customers return to sales service from transportation service in the past 12 months?

A. No customers returned to sales service fro transportation service in the past year.

Q. Does this conclude your testimony?

A. Yes it does.