DG 05-147

NORTHERN UTILITIES, INC.

2005/2006 Winter Cost of Gas

Order Regarding the Cost of Gas Rates and Local Distribution Adjustment Clause Rates and Other Rates

ORDER NO. 24,540

October 31, 2005

APPEARANCES: Seth L. Shortlidge, Esq. of Pierce Atwood LLP, and Patricia M. French, Esq., on behalf of Northern Utilities, Inc.; Rorie E.P. Hollenberg, Esq., on behalf of residential utility consumers; and Edward N. Damon, Esq., for the Staff of the New Hampshire Public Utilities Commission.

I. PROCEDURAL HISTORY

On September 13, 2005, Northern Utilities, Inc. (Northern) filed with the New Hampshire Public Utilities Commission (Commission) its Cost of Gas (COG) for the period November 1, 2005 through April 30, 2006, applicable to Northern's natural gas operations in the Seacoast area of New Hampshire. The filing was accompanied by supporting attachments and the Direct Testimony of Joseph A. Ferro, Manager of Regulatory Policy, and Francisco C. DaFonte, Director of Gas Control. On September 14, 2005, Northern filed with the Commission revised tariff sheets regarding the annual update of Appendices A and C of the Delivery Terms and Conditions pursuant to the requirements of *Gas Restructuring-Unbundling and Competition in the Natural Gas Industry*, 86 NH PUC 131, Order No. 23,652 (2001). On September 15, 2005, Northern filed with the Commission a Motion for Protection from Public Disclosure and Confidential Treatment regarding Attachment II of the updated Appendices.

On September 21, 2005, the Commission issued an Order of Notice scheduling a hearing for October 20, 2005. On September 26, 2005, the Office of the Consumer Advocate

(OCA) filed with the Commission a notice of intent to participate in this docket on behalf of residential utility ratepayers consistent with RSA 363:28. There were no other intervenors in this docket. On September 30, 2005, Northern filed a Motion for Protection from Public Disclosure and Confidential Treatment regarding the resource, supplier identity and cost information contained in Northern's calculation of the COG, N.H.P.U.C No. 10, Nineteenth Revised Page 38 and materials provided in support thereof.[1]

On October 19, 2005, Staff filed with the Commission a request to reschedule the hearing to October 26, 2005, which was granted by secretarial letter that same day. Also on October 19, 2005, the OCA filed with the Commission the Direct Testimony of Kenneth E. Traum. On October 20, 2005, Northern filed with the Commission a revised 2005/2006 Winter COG, including supporting attachments, together with an Amended Motion for Protection from Public Disclosure and Confidential Treatment regarding cost information contained in the materials provided in support of Northern's initial, September 13, 2005 COG filing and Northern's revised calculation of its COG.[2] On October 21, 2005, Staff filed the Direct Testimony of George R. McCluskey. The hearing before the Commission was held as scheduled on October 26, 2005.

II. POSITIONS OF THE PARTIES AND STAFF

A. Northern

Northern witnesses Joseph A. Ferro and Francisco C. DaFonte addressed the following issues: 1) calculation of the COG rates; 2) reasons for the increase and customer bill impacts; 3) supply reliability and price stability; 4) the Local Distribution Adjustment Clause (LDAC) charges and rates; 5) the pilot Residential Low Income Assistance Program (RLIAP); 6)

[1] These documents relate to information used to prepare the Winter 2005/2006 COG filed on September 13, 2005.
[2] Attached to this Motion were new redacted pages. Northern also filed the unredacted pages.

the transportation supplier balancing charge, peaking service demand charge and capacity allocators; and 7) allocation of fixed demand costs between Northern's New Hampshire and Maine Divisions.

1. Calculation and Impact of the Firm Sales COG Rates

According to Northern's revised COG filing, the proposed 2005/2006 Winter average residential firm sales COG rate of $1.3001 per therm is comprised of anticipated direct gas costs, indirect gas costs and various adjustments. Anticipated direct gas costs total $46,896,213 and are decreased by adjustments totaling $122,050 (a deferral of Winter 2004/2005 jurisdictional demand costs of $692,273 is offset by a prior period under-collection of $507,255 and interest of $62,968). Anticipated indirect gas costs total $1,100,896, consisting of production and storage capacity, working capital, bad debt and overhead charges. The gas costs to be recovered over the 2005/2006 Winter period (anticipated direct and indirect costs and adjustments) total $47,875,058 and are divided by projected Winter period sales of 36,823,440 therms (based on 2004/2005 winter normalized sales and projected sales growth of one percent) to arrive at Northern's proposed average COG rate.

Northern applied the ratios established in its revenue-neutral rate redesign proceeding, *see Northern Utilities, Inc.*, 86 NH PUC 229 (2001), to the average residential COG rate to determine the proposed commercial and industrial (C&I) low winter use COG rate of $0.9501 per therm and the C&I high winter use COG rate of $1.4073 per therm.

Northern's proposed 2005/2006 Winter COG residential rate of $1.3001 per therm represents an increase of $0.2783 per therm from the average weighted 2004/2005 Winter COG rate of $1.0218 per therm. The combined impact of the proposed firm sales COG and

LDAC rates is an increase in the typical residential heating customer's winter gas costs of $263, which represents a 19.6% increase above last winter's rates.

2. Reasons for the Increase

According to Northern, the increase in the proposed COG rate, as compared to last winter's rate, can be primarily attributed to increases in the actual and projected natural gas commodity prices and demand charges.

3. Supply Reliability and Price Stability

Northern testified that its gas supply portfolio focuses on supply and resource diversity, so there is not too much reliance on any one resource, as well as on economic efficiencies and resource flexibility. By way of example, only 10% of Northern's total Winter period requirements (and only 5% of its design day requirements) come from the Gulf of Mexico. Northern has much more reliance on Canadian supplies, both from western Canada and Nova Scotia. As a result, Northern has little exposure to the supply resources at risk in the Gulf of Mexico, having experienced only a minor disruption on one day following the hurricanes. Northern expects no disruptions in its supplies for the Winter period.

Northern could not speak to the supply risks its transportation customers may face, as Northern is not responsible for those resources. Northern explained that if a marketer is unable to provide gas supplies for a transportation customer on Northern's system, and that customer continued to take gas off the system, it could compromise system reliability and impact Northern's firm sales customers. Northern has sent a letter to the marketers serving Northern's transportation customers inquiring as to whether the marketer is anticipating any supply problems or may be planning to return customers to Northern firm sales service, but have received no responses to date.

Northern testified that along with pre-purchased supplies in storage, under its hedging plan a substantial volume of index-priced supplies have been hedged for this winter, effectively locking in prices for approximately 77% of its Winter period supply. As a result of Northern's diverse supply portfolio and hedging, only 23% of its forecasted Winter period supply is subject to the extremely volatile natural gas commodity market, thereby ensuring a greater level of price stability than would otherwise be the case. Northern's filing includes anticipated savings from the hedging plan that exceed $3 million for the 2005/2006 Winter period.

4. LDAC Charges and Rates

Under Northern's proposal, surcharges and credits to be included in the LDAC rate for the winter period are related to environmental costs to remediate Manufactured Gas Plant (MGP) sites, costs related to exiting the Wells LNG peak shaving facilities contract, energy efficiency programs and the RLIAP.

In *Northern Utilities, Inc.*, 84 NH PUC 669 (1999), the Commission approved a plan for the recovery of costs related to the early termination of Northern's Wells LNG peak shaving facilities contract. Northern indicated the stipulation provided for recovery of $325,076 in year seven, which commences November 1, 2005. Northern's reconciliation of prior period costs and revenues resulted in an over-recovery which has been deducted from this year's recovery amount, resulting in a proposed Wells surcharge of $0.0053 per therm.

In *Northern Utilities, Inc.*, 83 NH PUC 580 (1998), the Commission approved a recovery mechanism for environmental response costs associated with former MGP sites. These costs are filed during Northern's winter COG proceedings for Commission review and are recovered over a seven-year period. Northern filed for recovery of unamortized deferred environmental response costs of $909,099, incurred from July 1, 2004 through June 30, 2005. The response expense is offset by a prior period over-collection of $43,928 and, combined with environmental response costs approved for recovery in prior years, results in $539,875 to be recovered from ratepayers over the upcoming year. This yields a proposed environmental response cost rate of $0.0101 per therm to be applied from November 1, 2005 through October 31, 2006.

In *Energy-Efficiency Programs for Gas Utilities,* 87 NH PUC 892 (2002), the Commission approved the implementation of energy efficiency programs for New Hampshire's natural gas utilities. The LDAC rate includes a proposed energy efficiency surcharge of $0.0078 per therm for residential customers and $0.0099 per therm for C&I customers, effective November 1, 2005 through October 31, 2006.

5. RLIAP

In *New Hampshire Natural Gas Utilities*, Order No. 24,508 (September 1, 2005), the Commission approved implementation of a pilot RLIAP for New Hampshire's natural gas utilities. The LDAC rate includes a proposed RLIAP surcharge of $0.0050 per therm for all firm sales and transportation customers, effective November 1, 2005 through October 31, 2006. The charge is designed to recover $267,656, of which $40,000 is for the estimated administrative and programming costs associated with the start up of the program and the remainder is for the projected revenue shortfall resulting from the discounted rate for qualifying customers.

6. Revised Transportation Charges and Allocators

In *Gas Restructuring-Unbundling and Competition in the Natural Gas Industry,* Order No. 23,652, *supra*, the Commission approved a supplier balancing charge and peaking service demand charge to be updated once a year, commencing with the November billing month. Supplier balancing charges are the charges that suppliers are required to pay Northern for balancing services as Northern attempts to meet the shifting loads for the supplier's customer pools. Peaking service demand charges reflect Northern's peaking resources and associated costs.

Northern proposes to increase the supplier balancing charge from $0.75 per MMBtu to $0.77 per MMBtu of daily imbalance volumes and the Peaking Service Demand Charge from $18.00 per MMBtu of peak MDQ to $22.49 per MMBtu of Peak MDQ. The increases are based on an update of volumes and costs used in calculating the charges. Finally, the capacity allocator percentages, which are used to allocate pipeline, storage and local peaking capacity to a customer's supplier under the mandatory capacity assignment required by New Hampshire for firm transportation service, have been updated to reflect Northern's supply portfolio for the upcoming year.

7. Allocation of Fixed Demand Costs

Mr. Ferro discussed the history and purposes of the "Proportional Responsibility" (PR) allocation methodology in use in Maine and New Hampshire and acknowledged the accuracy of Staff witness McCluskey's testimony on these matters. In *Northern Utilities, Inc.*, 80 NH PUC 685 (1995), the Commission approved Northern's use of the PR allocation methodology, contingent upon acceptance of the same methodology by the Maine Public Utilities Commission (MPUC),[3] in order to allocate Northern's fixed, capacity related demand costs between the Maine and New Hampshire Divisions. Northern noted that the methodology 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 weighted monthly peak demands during the design year and then allocates the assigned monthly demand costs to each Division on

[3] The MPUC approved Northern's use of the PR methodology as well.

the basis of monthly firm sendout under design weather conditions. Northern stated that both Commissions acknowledged that the PR methodology was a fairer way of allocating those costs, which had previously been allocated on the basis of firm sendout volumes only, without assigning costs to individual months. Northern stated that it is fair to allocate *variable* commodity costs on the basis of firm sendout volumes only, but it is not fair to allocate *fixed* capacity costs on that basis alone because the planned-for capacity levels primarily reflect peak system demands.

Northern stated that by the late 1990s, sales service customers in Maine and New Hampshire were allowed to switch to transportation service. Mr. Ferro characterized the resulting impact on capacity cost allocation as an "ebb and flow" situation where, depending on the circumstances in each state, one state might be adversely affected by customers in the other state switching from firm sales to transportation service.

In *Re Gas Restructuring-Unbundling and Competition in the Natural Gas Industry,* Order No. 23,652, *supra*, the Commission approved 100% mandatory capacity assignment for Northern's New Hampshire customers switching from firm sales service to transportation service. New Hampshire customers who had switched on or before March 14, 2000 were treated as being "grandfathered," meaning that they did not have to take Northern's capacity. By contrast, Maine did not require mandatory capacity assignment.

Mr. Ferro stated that after the Commission Staff and the OCA had raised with Northern New Hampshire's increasing allocation of capacity costs,[4] it became apparent to Northern that there has been an inequitable allocation of costs to New Hampshire customers caused by of the high levels of switching in Maine (compared to the situation in New Hampshire), which itself was attributed to the lack of capacity assignment in Maine.

[4] *See* Docket No. DG 04-162 and *Northern Utilities, Inc.*, Order No. 24,389 (October 29, 2004).

Recognizing the bias in the approved allocation methodology, Mr. Ferro testified that the cost allocation methodology "could be, and soon should be, modified to recognize capacity quantities and associated sendout to certain Maine transportation load, so that the operation of the allocation process results in a fair assignment of costs between the two divisions."

Despite Mr. Ferro's admission that the current cost allocation methodology is biased against New Hampshire, he believes that Northern should be allowed full recovery of all prudently incurred costs through the approved PR allocation methodology. Mr. Ferro further claimed that it is appropriate for Northern to charge New Hampshire customers for the costs associated with serving certain Maine transportation customers because the approval of the PR allocation methodology by the two Commissions in 1995 constitutes a contract between the two Commissions that cannot be changed unilaterally. Northern stated that tariff provisions and other regulatory directives governing how costs are treated should be considered the equivalent of, or in lieu of, a contract.

Northern stated that it has taken steps to modify the cost allocation methodology. Specifically, Northern submitted a comprehensive tariff filing with the MPUC on February 22, 2005 which includes mandatory capacity assignment. (MPUC Docket No. 2005-87); in addition, at the request of Northern, both the Commission and MPUC opened a joint investigation into the operation of the allocation formula (Commission Docket No. DG 05-080 and MPUC Docket No. 2005-273). Northern recounted that the parties to the proceedings have been holding joint sessions and have two days of meetings scheduled in the first week of November, which Northern described as a critical period in the negotiations to resolve the cost allocation issue. Northern expressed concern that a Commission decision on cost allocation in this docket that changes the *status quo* could negatively impact the outcome of those negotiations.

Also in recognition of the apparent inequity occurring under the current allocation methodology, Northern previously agreed to defer $100,623 of Summer COG[5] costs associated with the capacity requirements of Maine customers who switched from firm sales to transportation service after March 14, 2000. In the instant filing, using the Summer period deferral as a precedent, Northern included a $692,273 deferral of those costs incurred during the 2004/2005 Winter period as a good faith gesture, pending a settlement agreement with the parties in this proceeding or a resolution of the issues in Docket No. DG 05-080.

In response to the testimony of Staff witness George McCluskey, Northern stated that his proposal to remove the 2005/2006 Winter period forecasted capacity costs in question plus the proposed refund of almost $700,000 associated with 2004-2005 Winter period would result in a reduction in the COG of approximately $2 million, which compares with only $50 million of annual non-gas revenues. Northern claimed that such a large reduction in revenues could impact the credit terms with its suppliers. Northern also argued the proposition advanced by Mr. McCluskey, that Northern does not incur capacity costs related to New Hampshire's grandfathered customers but does incur capacity costs for all of Maine's transportation customers, has yet to be determined. Northern stated that it operates its system on an integrated basis and capacity is not purchased for specific customers.

Northern also took exception to Mr. McCluskey's statements that a precedent had been set for deferring forecasted capacity costs shifted from Maine and that Northern should have anticipated such treatment and sought recovery of those shifted costs in Maine. Northern argued that it could only have expected the deferral of actual historic costs, which Northern said it has been doing. Finally, Northern stated that any changes to the PR methodology resulting from settlement of the other dockets can and will be reflected in a revision to Northern's cost of

[5] Northern maintained that these costs related to the 2004 Summer period.

gas, which Northern contends is a more timely, precise and reasonable approach than that recommended by Mr. McCluskey.

In response to the testimony of OCA witness Kenneth Traum, Northern stated that OCA's recommendation to disallow prudently incurred capacity costs was unfair. Northern reiterated that it has the right to recover 100% of its prudently incurred costs.

B. OCA

The OCA supported the rate changes proposed by Northern in its COG filing, with the exception of the COG rates. OCA witness Kenneth E. Traum testified that Northern should not be allowed to recover $1,346,838 of winter gas costs related to fixed demand costs allocated to New Hampshire and that the COG rates should be recalculated to reflect that reduction in gas costs.

Mr. Traum addressed the allocation of fixed demand costs between Northern's New Hampshire and Maine Divisions, noting that the allocation methodology was set prior to the establishment of transportation service (customer choice), which has developed differently in each state. According to the OCA, with New Hampshire requiring customers who switch from sales to transportation service to pay 100% of the capacity costs Northern has incurred to serve those customers and Maine not charging switching customers any of those costs, the allocation methodology is no longer equitable to Northern's New Hampshire customers. In response to Staff Data Request No. 3, Northern calculated that $1,346,838 of the capacity costs assigned New Hampshire for the 2005/2006 Winter period are costs attributable to serving Maine's transportation customers.

Mr. Traum noted that Northern has confirmed the inequities of the operation of the PR methodology to New Hampshire customers in its recent filings in Maine and that the New

Hampshire Commission has also recognized the unfair result of these differing treatments of capacity assignment in Maine and New Hampshire in its last two COG Orders, quoting Commission Order No. 24,460 (April 29, 2005) in which the Commission stated how such costs should be treated, "[c]learly, New Hampshire customers should not be responsible for costs incurred on behalf on Maine customers."

In closing, the OCA expressed its concern about rising costs and the impacts on ratepayers, though OCA recognized that the increase in costs is largely beyond Northern's control. The OCA supported the approval of the gas costs to serve New Hampshire, but could not support the costs associated with serving Maine transportation costs, which would have New Hampshire customers continue to pay costs subsidizing the Maine transportation customer and result in unreasonable and unjust costs to New Hampshire customers. The OCA disagreed with Northern's contention that settlement discussions between the parties in DG 05-080 and the related Maine dockets would be harmed by a Commission decision on the matter in this proceeding and recommended that the Commission find the PR allocation methodology to be unfair and inequitable at this time.

C. Staff

Staff supported the rate changes proposed by Northern in its COG filing, with the exception of the COG rates. Staff witness George R. McCluskey testified that approximately $1.35 million of fixed capacity costs that Northern is seeking to recover from New Hampshire customers over the 2005/2006 Winter period are the responsibility of Maine customers and recommended that the Commission remove those costs from the 2005/2006 Winter COG pending the outcome of the ongoing investigation with the MPUC of the continued reasonableness of the PR Methodology in Docket No. DG 05-080.

Mr. McCluskey explained that when the MPUC authorized all C&I customers to switch from firm sales to transportation service, effective November 1, 1999, it did not require those customers to pay the fixed capacity costs incurred by Northern to serve those customers. According to Staff, the decision not to require switching customers to pay their fair share of fixed capacity costs has encouraged significant numbers of firm sales customers in Maine to switch to transportation, which in turn has led to shifting costs to the New Hampshire Division.

Mr. McCluskey stated that New Hampshire's share of the total fixed capacity costs has risen from approximately 47% just prior to the adoption of the MPUC's expanded transportation policy in 1999 to 57% for the twelve-month period ending April 2006, resulting in a $1.35 million cost shift in just the 2005/2006 Winter period alone. Mr. McCluskey explained that the $1.35 million cost shift is calculated using a three step process that adjusts for Maine and New Hampshire transportation customers for which Northern does not incur fixed capacity costs. New Hampshire transportation customers that switched on or before March 14, 2000, the date on which New Hampshire implemented mandatory capacity assignment, are excluded in the calculation because Northern is not obligated to take back those customers and, therefore, does not plan for their return or, in his view, incur capacity costs to backstop these customers. He stated the same is not true for Maine customers that switched on or before March 14, 2000, because Northern believes that it has an obligation to backstop all firm transportation customers in Maine.

Mr. McCluskey stated there is precedent supporting Staff's recommendation to remove the $1.35 million as Northern entered into an agreement with Staff and the OCA to remove the estimated cost shift from its 2005 Summer period COG. Northern also proposed in the instant proceeding to refund the estimated cost shift collected during the 2004/2005 winter period.

Mr. McCluskey noted that the financial impact on Northern of removing those costs from the winter gas costs to be recovered from New Hampshire could have been mitigated had Northern anticipated the recommendation (a reasonable expectation given the outcome of Northern's 2005 Summer period COG proceeding) and sought recovery of the shortfall in Maine. In addition, he maintained the financial harm to Northern must be balanced against the financial harm to customers of including in rates costs Northern candidly agrees are attributable to the failure to assign capacity costs to Maine transportation customers.

Mr. McCluskey averred that, in his view, the PR methodology no longer achieves the goal of an equitable allocation of capacity costs. Mr. McCluskey pointed out that Northern recognizes that fact, as evidenced by Northern's testimony in Maine Docket No. 2005-480. In that proceeding, according to Mr. Ferro, discussions had taken place in Docket No. 2005-087 on the continued reasonableness of the PR Methodology, prompted by "the increasing awareness of the parties that the New Hampshire Division allocation factors were increasing due to declining Maine Division firm sales load." Mr. Ferro continued,

> "[t]his decline is the result of Maine customers switching from firm sales to transportation service, without being assigned any of Northern's capacity. This development has caused unassigned capacity costs (approximately 50%) to be allocated to New Hampshire firm customers and Maine firm sales customers."

Accordingly, Mr. McCluskey maintained that removing the shifted costs from the 2005-2006 Winter period COG pending the outcome of Docket No. DG 05-080 is consistent with the premise of the 1995 Commission Order, which was to ensure fairness in the allocation of capacity costs.

Mr. McCluskey further testified that a decision by the Commission to remove the \$1.35 million of contested costs would not impact settlement negotiations taking place in Docket No. DG 05-080, as the parties already know Staff's position, which is consistent with the proposed treatment of those costs in this proceeding.

III. COMMISSION ANALYSIS

After careful review of the record in this docket, we approve the proposed energy efficiency, Wells exit fee, environmental response costs and RLIAP surcharges, as these charges result in just and reasonable LDAC rates pursuant to RSA 378:7.

However, based on the record in this docket, we do not approve Northern's proposed COG rates as filed. It appears all parties are in agreement that the proposed rates include significant costs related to serving Maine transportation customers. As we pointed out in Order No. 24,460 (April 29, 2005) regarding the 2005 Summer period COG, "[c]learly, New Hampshire customers should not be responsible for costs incurred on behalf of Maine customers." This observation was based on an application of the well-accepted cost causation principle.

We note that Northern did not dispute the cost shifting assertion of Staff and the OCA, *i.e.*, that some of the fixed capacity costs incurred by Northern to backstop transportation customers in Maine have been collected from customers in New Hampshire. In light of this, Northern stated that the PR methodology could and should be changed to make the allocation procedure more equitable. Northern was not willing to agree, however, that the flaw in the current methodology means that the capacity costs it seeks to recover from New Hampshire customers are unreasonable. Northern's rationale is that the PR methodology was approved for use by Northern in 1995 and that, until it is found unjust or unreasonable and replaced with a different method, the costs allocated to New Hampshire should be deemed reasonable and hence recoverable.

Cost shifting among Northern's customers is the subject of an open docket, Docket No. DG 05-080; how those costs are ultimately treated has yet to be determined. Nonetheless, a reasonable estimate of those contested costs has been calculated to be $1.35 million. We direct Northern, therefore, to exclude the resulting $1.35 million from rates for the 2005/2006 Winter period and amend its COG rates accordingly. In so doing, however, we recognize Northern's right to request recovery of the disputed costs in Maine or in a future New Hampshire COG proceeding following the completion of Docket No. DG 05-080. This is consistent with our treatment of the 2005 Summer period estimated cost shift in Docket No. DG 04-162.

Northern made three additional arguments in support of its cost recovery request. First, Northern asserted that the Commission is precluded from adopting Staff's recommendation absent an agreement with the Maine Commission to replace the PR methodology with a new or modified cost allocation methodology that assures full recovery of Northern's prudently incurred costs. Second, Northern contended that adoption of Staff's position could have a chilling effect on the ongoing negotiations in Docket No. DG 05-080 to develop a new or modified cost allocation procedure. Finally, Northern argued that adoption of Staff's recommendation would unduly lower its credit rating and hence put at risk its ability to purchase gas supplies to serve customer demands.

We reject Northern's claim that a "contract" exists between the Maine and New Hampshire Commissions that constrains either Commission's ability to review the reasonableness of the allocated costs and make changes to the methodology as necessary. The

New Hampshire Commission is not a party to a written agreement with the Maine Commission regarding the interstate allocation of fixed capacity costs. Moreover, the contract issue is not ripe for resolution in this proceeding and is better addressed in Docket No. DG 05-080.

Northern's claim that the negotiations in DG 05-080 would be adversely affected if we removed $1,346,838 of capacity costs from the COG is unpersuasive. We find that Northern failed to provide any rationale for why the Maine parties would react negatively to a decision that conditioned the recovery of capacity costs in New Hampshire on the outcome of Docket No. DG 05-080.

Finally, we reject the claim that approval of Staff's recommendation would reduce cash flow during the upcoming Winter period to such a degree that Northern's credit would be adversely impacted, which in turn would jeopardize its ability to secure gas supplies to meet customer loads. We note that in this proceeding Northern has offered no written or oral testimony in support of its claim that the financial impact of our decision would adversely affect its ability to secure supplies to meet customer demands.

Regarding Northern's offer to credit New Hampshire customers for the Winter 2004-2005 estimated cost shift ($692,273), we believe that this offer was made subject to Northern receiving approval to recover all of its projected 2005/2006 Winter period gas costs. Because by this Order we reject that request we find, based on the testimony of Mr. Ferro, that the offer is no longer on the table and that the conditions in Order No. 24,460 (April 29, 2005) relating to the reservation of Staff's rights back to the 2004 summer period remain in effect. That is, $692,273 will not be credited to New Hampshire customers and Staff continues to reserve its right to request a refund of the $692,273 cost shift at a later time.

Regarding other issues not related to the PR methodology, we note that the rates are significantly higher than in past winters, reflective of existing conditions in the energy market. There is extreme volatility in the energy market at present, due to a number of issues, including the impacts of Hurricanes Katrina and Rita on natural gas production. Natural gas is an unregulated commodity and as its price increases in response to market conditions, it is inevitable that New Hampshire's natural gas customers will see a similar increase in their rates. At the same time, however, it is important to point out that the cost of gas mechanism is structured in a way that prevents the utility from realizing increased profits when the cost of gas increases. Finally, we note that Northern's diverse portfolio and hedging plans help sustain reliability and cushion the impact of the recent run up in gas prices, without which this winter's projected gas costs would have been approximately $3 million higher, according to figures provided by Northern.

In closing, we note there are three pending Motions for Protection from Public Disclosure and Confidential Treatment filed by Northern. We will issue a separate written order ruling on these Motions in the near future.

Based upon the foregoing, it is hereby

ORDERED, that Northern's proposed 2005/2006 Winter period COG rates for the period of November 1, 2005 through April 30, 2006 are REJECTED to the extent set forth above; and it is

FURTHER ORDERED, that Northern shall recalculate the COG rates to remove $1,346,838 in costs in accordance with this Order; and it is

FURTHER ORDERED, that Northern may, without further Commission action, adjust the approved COG rates upward or downward monthly based on Northern's calculation of the projected over or under-collection for the period, but the cumulative adjustments shall not exceed twenty percent (20%) of the approved unit cost of gas, *i.e.*, the minimum and maximum rates as set above; and it is

FURTHER ORDERED, that Northern shall provide the Commission with its monthly calculation of the projected over- or under-calculation, along with the resulting revised COG rates for the subsequent month, not less than five (5) business days prior to the first day of the subsequent month. Northern shall include revised tariff pages 38 & 39 - Calculation of Cost of Gas Adjustment and revised rate schedules if Northern elects to adjust the COG rates; and it is

FURTHER ORDERED, that the over- or under-collection shall accrue interest at the Prime Rate reported in the *Wall Street Journal*. The rate is to be adjusted each quarter using the rate reported on the first date of the month preceding the first month of the quarter; and it is

FURTHER ORDERED, that Northern's proposed 2005/2006 Local Distribution Adjustment Clause per therm rates for the period of November 1, 2005 through October 31, 2006 as filed in Proposed Eighth Revised Page 56, Superseding Seventh Revised Page 56, are APPROVED effective for service rendered on or after November 1, 2005 as follows:

	Energy Efficiency	**Envir. Response Costs**	**Wells Exit Fee**	**Residential Low Inc. Assistance**	**LDAC**
Residential Heating	$0.0078	$0.0101	$0.0053	$0.0050	$0.0282
Residential Non-heating	$0.0078	$0.0101	$0.0053	$0.0050	$0.0282
Small C&I	$0.0099	$0.0101	$0.0053	$0.0050	$0.0303
Medium C&I	$0.0099	$0.0101	$0.0053	$0.0050	$0.0303

Large C&I	$0.0099	$0.0101	$0.0053	$0.0050	$0.0303

FURTHER ORDERED, that Northern's proposed transportation supplier balancing charge of $0.77 per MMBtu of daily imbalance volumes, as filed in Proposed Fifth Revised Page 154, Superseding Fourth Revised Page 154, is APPROVED; and it is

FURTHER ORDERED, that Northern's proposed transportation peaking service demand charge of $22.49 per MMBtu of peak MDQ, as filed in Proposed Fifth Revised Page 154, Superseding Fourth Revised Page 154, is APPROVED; and it is

FURTHER ORDERED, that Northern's proposed transportation capacity allocators as filed in Proposed Fourth Revised Page 169, Superseding Third Revised Page 169, are APPROVED; and it is

FURTHER ORDERED, that Northern shall file properly annotated tariff pages in compliance with this Order no later than 15 days from the issuance date of this Order, as required by N.H. Admin. Rules, Puc 1603.

By order of the Public Utilities Commission of New Hampshire this thirty-first day of October, 2005.

Thomas B. Getz Chairman	Graham J. Morrison Commissioner	Michael D. Harrington Commissioner

Attested by:

Lori A. Normand
Assistant Secretary