DG 00-063

ENERGYNORTH NATURAL GAS, INC.

Revenue Neutral Rate Redesign

Order Approving Settlement Agreement

O R D E R N O. 23,675

April 5, 2001

APPEARANCES: McLane, Graf, Raulerson, and Middleton by Steven V. Camerino, Esq. for EnergyNorth Natural Gas, Inc.; Office of the Consumer Advocate by Kenneth E. Traum, Finance Director on behalf of residential utility consumers; and Larry S. Eckhaus, Esq. for the Staff of the New Hampshire Public Utilities Commission.

I. PROCEDURAL HISTORY

On March 23, 2000, EnergyNorth Natural Gas, Inc. (ENGI) d/b/a KeySpan Energy Delivery New England (KeySpan) filed with the New Hampshire Public Utilities Commission (Commission) a Notice of Intent to File Rate Schedules. On April 19, 2000, KeySpan filed a Request for Waiver of Certain Rules Pertaining to Filing of Rate Case, in particular, Rules Puc 1604.01(a)(1)-(6), 1604.01(a)(8)-(27), 1604.06, 1604.07, and 1203.02(d)(1) in accordance with the provisions of Puc 201.05. On April 21, 2001, KeySpan filed with the Commission a request for temporary waiver of Rules Puc 1203.02(e). On May 5, 2000, the Commission determined that a temporary waiver of the designated filing rules serves the public interest, would not disrupt the orderly conduct of the proceeding, and would allow KeySpan time to comply with Puc 1203.02.

On May 8, 2000, KeySpan submitted the proposed rate changes. The filing included the proposed tariff revisions and supporting documentation, including the prefiled testimony and exhibits from Mark G. Savoie, Manager of Regulatory Affairs for ENGI, and James L. Harrison, Vice President of Management Applications Consulting, Inc.

According to KeySpan, the proposed rates are designed to be revenue neutral. That is, in total, the proposed rates would produce the same total revenue as the existing rates, assuming consistent billing determinants; however, the proposed delivery rates for individual rate classes and customers would change.

KeySpan proposed identical delivery rates for both sales and delivery customers. The delivery rates would contain no gas supply related costs so that customers will be indifferent, from a delivery rate perspective, as to whether they opt for supply service from KeySpan or from another supplier. KeySpan stated that the proposed delivery rates are designed to more closely reflect the cost of serving the various customer classes.

KeySpan also proposed a revised Cost of Gas (COG) clause so that direct and indirect gas supply related costs will be recovered in the COG. The revised COG clause provides for load factor based gas cost rates that would more closely reflect the cost to provide gas supply service than the current COG rate, which is uniform for all classes.

On May 12, 2000, the Office of the Consumer Advocate (OCA) filed a Notice of Intent to Participate in this docket on behalf of residential utility ratepayers pursuant to the powers and duties granted to the OCA under RSA 363:28. By an Order of Notice issued May 15, 2000, the Commission scheduled a Prehearing Conference and Technical Session for June 8, 2000, and set deadlines for intervention requests and objections thereto.

On June 9, 2000, KeySpan filed with the Commission the display advertisement which, pursuant to N.H. Admin. Rules Puc 203.01(b) and 203.01(d), noticed the public hearing scheduled for June 8, 2000 and detailed the specific rate impacts for the Residential classes and general rate impacts for the Commercial and Industrial classes. KeySpan also filed the bill insert pursuant to Rules Puc 1203.02(c).

On June 30, 2000, the Business & Industry Association of New Hampshire (BIA) filed a Petition for Late Intervention. However, the BIA did not participate in the proceeding and is not a signatory to the Settlement Agreement.

By Order dated July 6, 2000, the Commission approved the proposed procedural schedule filed on June 20, 2000 by the Commission Staff (Staff), which was agreed to by KeySpan and the OCA (the Parties). Order No. 23,525. The procedural schedule provided for technical sessions, rolling data requests, OCA-sponsored testimony, Staff-sponsored testimony, and hearings to be held during December 2000. The Commission’s Order approving the procedural schedule also contemplated the possible consolidation of KeySpan’s proceeding with Docket DG 00-046, Northern Utilities, Inc., to the extent that there may be issues common to both proceedings.

On August 29, 2000, the Commission granted the BIA's intervention stating that the intervention would not impair the orderly and prompt conduct of the proceeding.

On September 1, 2000, the OCA timely filed the testimony of Steven W. Ruback, Principal of the Columbia Group, Inc.

On October 12, 2000, Staff timely filed the testimony of Stephen P. Frink, Assistant Finance Director for the Commission, and Michelle A. Caraway, Utility Analyst III for the Commission.

On November 15, 2000, in accordance with the procedural schedule, Staff submitted an Assented to Motion to Consolidate and Postpone Hearings in both this proceeding and Docket DG 00-046, Northern Utilities, Inc.

On November 22, 2000, the Commission informed the parties, by Secretarial Letter, that it had determined consolidation of the hearings in Docket DG 00-046, Northern Utilities, Inc. and Docket DG 00-063, EnergyNorth Natural Gas, Inc. would promote the orderly and efficient conduct of the proceedings and that postponement could increase the opportunity for settlement. The consolidated hearing was scheduled for January 23, 2001.

On November 27, 2000, KeySpan filed the Rebuttal Testimony of James L. Harrison. On the same date, the OCA filed the Prefiled Rebuttal Testimony of Steven W. Ruback.

On December 8, 2000, Staff notified the Commission that the Parties and Staff had agreed to establish a procedural schedule, including settlement conferences and a revised hearing date, for the remainder of the proceeding. This modified procedural schedule was approved by the Commission on December 12, 2000. Order No. 23,599.

The OCA and Staff propounded data requests to KeySpan, and KeySpan and Staff propounded data requests to the OCA. In addition, technical/settlement conferences were held on December 19, 2000 and January 5, 17, and 23, 2001.

On January 10, 2001, Staff requested a revision of the procedural schedule approved by the Commission on December 12, 2000 in Order No. 23,599. Staff requested that a hearing be scheduled for February 8, 2001. On January 18, 2001, the revised procedural schedule was approved by the Commission by Secretarial Letter.

On January 31, 2001, KeySpan filed the Settlement Agreement on behalf of KeySpan, OCA and Staff.

II. INITIAL POSITIONS OF THE PARTIES AND STAFF

A. KeySpan

KeySpan had two broad objectives in proposing its rate redesign: (1) to redesign existing rates to be consistent with the Commission’s rate design precedent, in particular, that rates should be cost-based, and (2) to design rates that would facilitate increased retail competition on KeySpan’s system. KeySpan's filing is intended to be revenue neutral and is comprised of three major components. First, KeySpan would fully unbundle its gas supply and delivery functions to ensure that the same rates for delivery service are being charged to both sales and delivery-only customers so that (a) there is no cost-based subsidy between customers taking bundled sales service and those taking delivery-only service, and

(b) KeySpan is indifferent, from a net revenue perspective, as to whether a customer remains a sales customer or migrates to delivery-only service. Second, KeySpan would change its rate classifications and class specific revenue requirements based on its marginal cost of service study presented in this proceeding. Third, KeySpan would modify its COG clause to implement load-factor-specific gas cost rates for Residential and Commercial and Industrial customers. KeySpan indicated that the revisions to its delivery service rates and COG clause would send clearer price signals to customers and would facilitate competition since KeySpan's rates would reflect the underlying costs for both the delivery and gas supply service it provides to the various customer classes.

B. Office of the Consumer Advocate

The OCA urged the Commission to consider both the results of the marginal and embedded cost of service studies as well as traditional long-standing non-cost rate design criteria of rate continuity, gradualism, fairness and public acceptability when allocating revenue requirements and designing rates. The OCA's consultant did not have significant disagreements with the methodologies used in the cost studies, although he did raise concerns about rate shock, specific rate increases, and related issues.

Further, the OCA recommended that the Commission defer a decision on the proposed modifications to the COG clause stating that the proposed COG mechanism reallocates more gas costs to Residential Heating customers at a time when gas commodity prices have increased dramatically, potentially leading to rate shock. The OCA states that in the settlement it entered into with KeySpan and Staff in Docket DE 98-124, Gas Restructuring, the OCA felt the most important aspect to Residential ratepayers was the implementation of competitive choice for Commercial and Industrial customers without shifting costs to the Residential classes. In this docket, KeySpan proposed significant changes to how gas costs would be assigned to customer classes, which would have shifted significant costs to the Residential class. Since the OCA viewed the rationale for this proposal as being to level the playing field for competition, the OCA viewed the proposal as being inconsistent with the settlement in Docket DE 98-124 and thus opposed a change to a load factor COG mechanism.

The OCA also recommended that the Commission reject the proposed increases to the customer charges for both the Residential Heating and Non-Heating classes. Finally, the OCA recommended that KeySpan submit for approval two incentive programs for customers that are already connected to the distribution system. The first is an incentive program to promote gas water heating and the second is an incentive to promote high efficiency gas furnaces for heating.

C. Staff

Staff is generally supportive of KeySpan's rate redesign. According to Staff, KeySpan's filing provided many benefits over the design of current rates including: movement to cost-based rates predicated upon the marginal cost of service study; identical delivery rates for sales and delivery customers; introduction of service-rendered billing; and introduction of a load factor based rate structure and COG clause. However, Staff raised the following concerns with the filing: the recovery of indirect gas costs in the COG clause and its implication for lost revenues recovered through the conservation surcharge and a need for consistent terminology for identification of rate classes between KeySpan and Northern Utilities, Inc. Further, Staff provided testimony opposing the OCA’s recommendation to introduce two incentive programs for customers that are already connected to the distribution system because the incentive programs would go beyond the scope of the instant proceeding.

III. SETTLEMENT AGREEMENT

The terms of the Settlement Agreement are summarized below:

1. Rate Class Names

The Parties and Staff agree that KeySpan's Commercial and Industrial (C&I) rate class names shall be designated as "high winter" or "low winter," and "low annual," "medium annual," or "high annual," as applicable.

2. Rate Class Definitions

The Parties and Staff agree that KeySpan's Residential customer classes will retain their existing designations: Residential Space Heating (RSH) and Residential Non-Space Heating (RNSH). The Parties and Staff further agree that KeySpan's C&I classes will be re-designated as follows:

Designation	**Annual Use**	**Percent Winter Use of Annual Use**[1]	**Percent Annual Use of Winter Use**[2]
LAHW	< or = 10,000 therms	> or = 67%	N/A
LALW	< or = 10,000 therms	< 67%	N/A
MAHW	> 10,000 therms and < or = 100,000 therms	> or = 67%	N/A
MALW	> 10,000 therms and < or = 100,000 therms	< 67%	N/A

[1]The percent winter use of annual use is determined by dividing the winter period (November to April inclusive) usage by the usage over a full twelve month.

[2]The percent annual use of winter use is determined by dividing the average use over a full twelve month period by the average use for the months of December, January and February.

HAHW	> 100,000 therms	> or = 67%	N/A
HALW90	> 100,000 therms	< 67%	< 90%
HALW110	> 100,000 therms	< 67%	> or = 90% but < 110%
HALWG110	> 100,000 therms	< 67%	> or = 110%

These new C&I rate class designations replace the existing designations.

3. Rate Schedules

The Parties and Staff agree that KeySpan's revised tariff, to be filed as a compliance filing in accordance with this Agreement, should be approved effective May 1, 2001. The rates are as detailed on the schedule on the next page.

EnergyNorth Natural Gas, Inc. d/b/a KeySpan Energy Delivery
Summary of Proposed Rates

	RESIDENTIAL		**COMMERCIAL/ INDUSTRIAL LOW ANNUAL**		**COMMERCIAL/ INDUSTRIAL MEDIUM ANNUAL**		**COMMERCIAL/ INDUSTRIAL HIGH ANNUAL**			
Description	Non Space Heat	Space Heat	High Winter Use	Low Winter use	High Winter Use	Low Winter Use	High Winter Use	Load Factor <90%	Load Factor <110%	Load Factor >110%
	RNSH	RSH	LAHW	LALW	MAHW	MALW	HAHW	HALW90	HALW110	HALWG110
Eligibility										
Annual Usage, Therms	N/A		<=10,000		>10,000 & <=100,000		> 100,000			
Winter Usage, % of Annual	N/A	N/A	>=67%	<67%	>=67%	<67%	>=67%	<67%	<67%	<67%
Load Factor, Avg Use/ Dec-Feb Avg Use	N/A	N/A	N/A	N/A	N/A	N/A	N/A	<90%	<110%	>=110%
Customer Charge, Month	$7.00	$10.00	$25.00	$25.00	$70.00	$70.00	$300.00	$300.00	$300.00	$300.00
Winter Rate										
Head Block Size	10	100	100	100	1,000	1,000	N/A	N/A	N/A	N/A
Head Block Rate	$0.2678	$0.2945	$0.3275	$0.2525	$0.2716	$0.1734	N/A	N/A	N/A	N/A
Tail Block Rate	$0.2364	$0.1739	$0.2135	$0.1636	$0.1800	$0.1193	$0.1591	$0.1074	$0.0799	$0.0345
Summer Rate										
Head Block Size	10	20	20	100	400	1,000	N/A	N/A	N/A	N/A
Head Block Rate	$0.2678	$0.2945	$0.3275	$0.2525	$0.2716	$0.1275	N/A	N/A	N/A	N/A
Tail Block Rate	$0.2364	$0.1739	$0.2135	$0.1636	$0.1800	$0.0734	$0.0728	$0.0514	$0.0410	$0.0188

A. Residential Customers

(1) The Parties and Staff agree that Residential Heating customers will be billed monthly. The monthly customer charge will be $10.00. The delivery service rates for this customer class are not seasonally differentiated (although the number of therms in each block do vary seasonally). The first block rate for both seasons is $0.2945 per therm; the second block rate is $0.1739 per therm.

These rates are designed to produce an increase of 6.0 percent in total revenue for the Residential Heating class as compared to test year revenues.

(2) The Parties and Staff agree that Residential Non-Heating customers will be billed monthly. The monthly customer charge will be $7.00. The delivery service rates for these customers are not seasonally differentiated. The first block rate for both seasons is $0.2678 per therm; the second block rate is $0.2364 per therm.

These rates are designed to produce an increase of 13.0 percent in total revenue for the Residential Non-Heating class as compared to test year revenues.

(3) All Residential customers will pay the same COG rate based on the total system firm sales average COG rate.

B. Commercial and Industrial Customers

(1) The Parties and Staff agree that eight new C&I rate classes will be established, replacing the existing C&I rate classes.

(2) The rates to the Low Annual, High Winter Use C&I customers (Rate LAHW) are designed to produce 2.8 percent less revenue than the test year rates produced for these customers.

The rates to the Low Annual, Low Winter Use C&I customers (Rate LALW) are designed to produce 3.3 percent less revenue than the test year rates produced for these customers.

The delivery service rates for these customers are not seasonally differentiated (although the number of therms in each block do vary seasonally for Rate LAHW).

(3) The rates to the Medium Annual, High Winter Use C&I customers (Rate MAHW) are designed to produce 4.9 percent less revenue than the test year rates produced for these customers.

The rates to the Medium Annual, Low Winter Use C&I customers (Rate MALW) are designed to produce 10.3 percent less revenue than the test year rates produced for these customers.

The delivery service rates for these customers are seasonally differentiated.

(4) The rates to the High Annual, High Winter Use C&I customers (Rate HAHW) are designed to produce 12.4 percent less revenue than the test year rates produced for these customers.

The rates to the High Annual, Low Winter Use C&I customers with a summer load factor below 90% (Rate HALW90) are designed to produce 9.8 percent less revenue than the test year rates produced for these customers.

The rates to the High Annual, Low Winter Use C&I customers with a summer load factor of at least 90% and less than 110% (Rate HALW110) are designed to produce 4.8 percent less revenue than the test year rates produced for these customers.

The rates to the High Annual, Low Winter Use C&I customers with a summer load factor equal to or greater than 110% (Rate HALWG110) are designed to produce 11 percent less revenue than the test year rates produced for these customers.

The delivery service rates for these customers are seasonally differentiated.

(5) Different COG rates apply to the C&I High Winter and various Low Winter classes based on the Market Based Allocation (MBA) COG analysis filed in the Direct Testimony of James L. Harrison in this docket. Ratios from the test year calculations will be used in future summer and winter COG filings to establish the C&I High and various Low Winter COG rates.

The following factors have been identified as variables to assist in predicting significant shifting of the MBA-based escalator of gas costs and resulting changes in the COG ratios:

(a) The percentage of migration from sales to transportation service in the C&I High and various Low Winter classes;

(b) The ratio of delivered costs of winter supplies to pipeline delivered supplies; and

(c) The July and August consumption for the C&I High and various Low Winter classes in relationship to annual consumption.

The above factors shall be filed annually by KeySpan for informational purposes. Significant changes in these factors are expected to signal the need to evaluate the COG ratios.

4. Revenue Proof

KeySpan provided a worksheet showing the calculation of the proposed rates and demonstrating that the proposed rates, in total, are designed to collect the same level of revenues as KeySpan’s test year rates.

5. Moving Indirect Gas Costs from Delivery Service Rates to the COG Clause

A. The Parties and Staff agree that KeySpan's indirect gas costs, previously included in base rates, will be moved from KeySpan's delivery service rates to its COG clause. These indirect gas costs relate to a portion of the revenue requirement associated with KeySpan's liquid propane (LP) and liquified natural gas (LNG) peaking facilities, gas dispatching and acquisition costs, administrative and general/miscellaneous expenses, as well as working capital allowance and bad debt expense related to purchased gas costs.

B. The Parties and Staff agree that KeySpan's test year revenue requirement associated with the LP and LNG peaking facilities related to gas supply service of $2,475,244 (see Direct Testimony of James L. Harrison, Schedule EN-2-7-4) and the other administrative and general/miscellaneous expenses totaling $607,266 (see Direct Testimony of James L. Harrison, Schedule EN-2-4-2,

p. 2) will be recovered through the COG clause each year. These indirect gas supply service revenue requirements will only change pursuant to a Commission rate order in a general rate case.

C. The Parties and Staff also agree that working capital allowance will be recovered through the COG clause at an amount equal to 0.56% of purchased gas costs. The Parties and Staff agree that bad debt expense will be recovered at an amount equal to 0.97% of total direct gas costs.

D. The Parties and Staff also agree that the lost incremental net revenues to be collected through the conservation charges will be adjusted downward to account for the amount of indirect gas costs that will be recovered through the COG clause.

6. Rate Redesign Case Expenses

The Parties and Staff agree that KeySpan will recover the reasonable and prudent expenses pertaining to the rate redesign proceeding. The Parties and Staff agree that one-half of this amount will be recovered from all delivery and sales customers and that one-half of this amount will be recovered solely from C&I delivery and sales customers. The Parties and Staff agree that this amount will be recovered from customers, via a per therm charge as a surcharge through the Local Delivery Adjustment Clause (LDAC). The amount of this surcharges is not included with this Agreement, but will be provided as part of KeySpan's compliance filing in this docket.

7. Settlement Implementation

The Parties and Staff agree that the terms of this Agreement are to be implemented effective May 1, 2001.

8. Service Rendered Billing

The Parties and Staff agree that service rendered billing for both delivery and sales services, including the COG clause, will be implemented effective May 1, 2001. The Parties and Staff recommend that the Commission waive application of NH Admin. Rules Puc 1203.05(b) to the extent necessary to implement this aspect of the Agreement and that the Commission consider a permanent rule change to the extent necessary or appropriate.

9. Cost of Service Studies

The Parties and Staff have not disputed the results of the

Marginal and Embedded Cost of Service Studies filed in the Direct Testimony of James L. Harrison for purposes of this docket. The Parties and Staff understand that KeySpan expects to use these Cost of Service Studies in future proceedings, subject to any future Commission decisions. Any party to such future proceedings may argue for a different cost of service methodology.

IV. COMMISSION ANALYSIS

Our review of this matter was conducted pursuant to RSA 378:5, which states:

> Whenever any schedule shall be filed with the commission stating new and higher rates, fares, charges or prices, which the public utility filing the same proposes to put into force, the commission may investigate the reasonableness of such proposed rates, fares, charges or prices.

Although the Commission held a hearing on this matter a required by RSA 378:28, it was not a contested one; rather, it entailed a review and discussion of the Settlement Agreement. Th Commission's practice of discharging its responsibilities through review of negotiated agreements such as this one is long-standing derives, in part, from RSA 541-A:38 which encourages settlements.

We have reviewed the terms of the Settlement Agreement well as KeySpan's filing and the supporting testimony and exhibit presented at the February 8, 2001 hearing. Based on our review o the record, we find that KeySpan's revenue neutral rate redesign petition, as amended by the terms of the Settlement Agreement, produces rates that are just and reasonable and in the public goo While the rate design is intended to be revenue neutral based on total test year revenues, it does impact each customer class differently. This differential impact on each rate class occurs because each rate is moved closer to cost, thereby sending custom more accurate price signals.

The filing of the petition was precipitated by several factors: a need to properly design rates before implementation of new model terms and conditions for expanded delivery-only service approved by the majority in Docket DE 98-124, Gas Restructuring, Order No. 23,652 (March 15, 2001); a need to address the inequity between delivery rates for sales versus transportation customers created in Docket DE 95-121, Re Northern Utilities, Inc., 82 NH P 566 (1995); and a desire to move further to cost-based rates recognizing that KeySpan has not had any adjustments to base rate eight years, EnergyNorth Natural Gas, Inc., 78 NH PUC 117 (1993). Indeed, the parties to the current proceeding were prompted by th Commission to continue to investigate further unbundling and to reduce rates to Commercial and Industrial customers:

> We intend to observe the development of firm transportation services in the coming months, and will consider further reduction in these rates to better reflect the cost to serve firm transportation customers. We instruct the LDCs, OCA and Staff to evaluate, prior to the summer 1998 cost of gas adjustment proceedings, the number of firm transportation customers, the revenue impacts of the rates as ordered herein, and the anticipated revenue impacts of further movement towards cost-based rates. At the time of the summer 1998 hearings, the LDCs shall propose another reduction in firm transportation rates, or provide evidence to demonstrate why such reduction is not in the public

> interest. The LDCs, OCA and Staff should work together over the coming 12 months to explore opportunities to continue to reduce these rates... Of course we retain the right to accelerate reductions or otherwise change the regulation of natural gas to encourage greater competition in the industry. Re Northern Utilities, Inc. 82 NH PUC 566, 570 (1997).

KeySpan stated at the February 8, 2001 hearing that for the other reasons cited above, a petition to move more toward cost-based ra was on the horizon even if KeySpan had not filed its rate redesig last year in response to Docket DE 98-124, Tr. at 74.

The new rate classes proposed by KeySpan are based upon load characteristics, such as how much gas is used and when that is used, as compared to end-use. Load characteristics are a driv factor of the costs of providing service. By designing rates bas on load characteristics, intraclass subsidies are minimized in addition to more closely aligning rate classes to their costs to serve.

The rate redesign provides identical delivery rates for Commercial and Industrial rate classes, dependent upon annual use load factor, regardless of whether the customer purchases its gas from KeySpan or not. This change removes the inequity that resul from Docket DE 95-121, Northern Utilities, Inc., when the Commiss reduced transportation rates without also reducing the delivery portion of bundled sales rates. The Commission notes a major advantage of this aspect of the settled rate design: it makes the utility indifferent from a revenue standpoint as to whether a customer opts for unbundled delivery service or continues bundled sales service. There should be no adverse effect on the utility it provides delivery service instead of bundled sales service.

Indirect gas costs (consisting of revenue requirements associated with KeySpan's local production facilities, gas dispatching and acquisition costs, the gas supply related portion bad debt expense, and all overhead costs related to these items) now be recovered through the COG clause. This, and the creation high and low load factor COG rates for Commercial and Industrial customers, prepare the rate structure for the advent of competiti by reducing the potential for suppliers to offer attractive rates those KeySpan customers with a lower cost to serve than the syste average COG rate.

We note that the target marginal cost-based class reven served as a guide in establishing the Settlement rates. Had the Settling Parties and Staff fully reflected the results of the marginal cost studies in the ratemaking process, the rate increas for the Residential classes would likely exceed those that were proposed. For example, the Settling Parties and Staff recommende monthly customer charges of $10.00 and $7.00 for Residential Heat and Residential Non-heating customers respectively, up from the current $7.89 and $5.68 respectively, but considerably short of t

$22-$23 shown in KeySpan's marginal cost study. These increases customer charges are not inconsistent with the Commission's last approved increases in customer charges of $4.16 and $1.95 approve Order No. 20,542, EnergyNorth Natural Gas, Inc.,77 NH PUC 354, 35 (1992).

Further, while a 6% increase in revenue requirements fo the Residential Heating class and a 13% increase for the Resident Non-Heating class appear substantial, one must also consider the monthly bill impact and the fact that KeySpan customers have not a base rate increase since April 1, 1993. The estimated average monthly rate increase for a typical Residential Heating customer $3.02; for the typical Residential Non-Heating customer the estim increase is $1.44.

The statutory standards for sufficiency of Commission ratemaking decisions do not require that the Commission determine outcome using any specific methodology, so long as the result is consistent with the "public interest" and the rates are "just and reasonable." *Appeal of Richards*, 134 N.H. 148 (1991). In *Richar* case, the New Hampshire Supreme Court determined that a tradition ratemaking approach was not required, by statute or federal Constitution, to analyze a rate plan before the Commission. The Court noted the well-established principle set out in *Federal Pow Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) that "the methodology used to set rates is irrelevant... Instead, it is th result reached that is important: '[i]f the total effect of the r order cannot be said to be unjust or unreasonable, judicial inqui is at an end.'" 134 N.H. at 164, quoting *Hope*, 320 U.S. at 602.

We believe that an "end result" review is particularly applicable to the consideration of settlement agreements, which, their nature, often require the parties to compromise positions a principles in order to reach an acceptable outcome. Thus, while Commission may not simply accept a proffered compromise of the parties as a resolution of a particular matter, and must conduct own independent review in order to ensure that the "public intere and "just and reasonable" standards have been met, it may do so without reliance upon any particular theory or methodology.

In this instance, while the Settlement Agreement may ha had its roots in marginal cost principles, the parties have shown that these have been tempered by a gradual application not inconsistent with our last rate design order with respect to the company. Most importantly, the Settlement results in a reasonabl dollar impact upon each rate class, even on those that will experience an increase. It appears that each party yielded some ground in order to arrive at this result, and we find that this achievement is consistent with the principles we are required to consider before we may grant an increase.

The Settlement Agreement states that Residential custom will continue to be billed the system average cost of gas while h and low load factor COG rates will be created for Commercial and Industrial customers. We believe that this condition is consiste with our order in Gas Restructuring which makes it more economica for smaller Commercial and Industrial customers to accept deliver only service and postpones discussion on extending competition to Residential classes. In effect, maintaining the average COG hold harmless the Residential customers from higher gas costs due to t effects of further restructuring.

Order No. 23,652 in Docket DE 98-124, Gas Restructuring states: "the date for implementation of restructuring shall be the subject of orders in Docket DG 00-046, ***Northern Utilities, Inc.***, and Docket DG 00-063, ***EnergyNorth Natural Gas, Inc.*** rate redesign proceedings." In its New Hampshire Gas Collaborative Final Report (Final Report), the Collaborative[3] recommended that there be a six-month period after issuance of a Commission order Docket DE 98-124 prior to the effective date of the new tariff provisions regarding delivery service.

> This period will be utilized to, among other things, develop and implement a consumer education program, design and test

[3]The Collaborative was open to, and consisted of, all intervenors and Staff in Docket DE 98-124. All parties did not attend all meetings. Ultimately, the Final Report was filed by Collaborative participants KeySpan, Northern, the OCA and Staff.

> electronic data interchange programs, and refine internal capacity assignment and algorithm procedures. Final Report at 11.

Since the effective date for new rates will be May 1, 2001, we wi authorize implementation of our order in Docket DE 98-124 effecti November 1, 2001, consistent with the beginning of the winter per to provide for the six-month lead time necessary to ensure system are in place and customer education and communications on unbundl services are developed.

Further, our approval of the Final Report in Docket DE 9 124 provided for the recovery of incremental costs that KeySpan h incurred, and will continue to incur, related to developing expan customer choice for Commercial and Industrial customers. Since O No. 23,652 provides for expanded choice to be effective November 2001, KeySpan shall be entitled to recover costs related to Docke 98-124 effective November 1, 2001. Therefore, we direct KeySpan file by September 15, 2001 a summary of its incremental restructu expenses broken down into major components and to provide copies all invoices for costs which KeySpan seeks to recover. KeySpan s also include in its filing the calculation of the per therm surch that would result from recovery scenarios from one to three years

The Settlement Agreement also provides for recovery of expenses related to the rate redesign proceeding. We shall requi KeySpan to file with the Commission by April 13, 2001 a summary o its rate case expenses broken down into major components and to provide copies of all invoices for costs which KeySpan seeks to recover. KeySpan shall also include in its filing the calculatio the per therm surcharge that would result from recovery scenarios from one to three years. The Commission will issue a subsequent order addressing the rate case expenses once the Staff has conduc a review and audit of the expenses and determined the rate impact the surcharge.

For KeySpan, our approval of the rate design creates new winter and summer periods. KeySpan's winter period will be the period November 1 through April 30 and the summer period will be 1 through October 31. These periods are consistent with New Hampshire's other two gas utilities. However, because KeySpan's summer period is currently April 1 through October 31 and KeySpan recently received approval of its 2001 Summer COG, Docket DG 01-0 Order No. 23,668 (March 29, 2001), it will be necessary for KeySp to include in its compliance filing revised COG rates reflecting movement of indirect gas costs from base rates to the COG mechani and the creation of the high and low load factor COG rates for Commercial and Industrial customers. We direct KeySpan to file i revised COG with the Commission by April 13, 2001 to provide Staf time to review the calculations of the new COG rates and ensure t compliance with our order today. We expect that there will be no change to projected gas costs as filed in Docket DG 01-037, KeySp 2001 Summer COG filing.

Based upon the foregoing, it is hereby

ORDERED, that the Settlement Agreement entered into among KeySpan, OCA and Staff is APPROVED; and it is

FURTHER ORDERED, that the rates delineated above are effective May 1, 2001; and it is

FURTHER ORDERED, that implementation of Order No. 23,652 (March 15, 2001) in Docket DE 98-124 is effective November 1, 2001; and it is

FURTHER ORDERED, that KeySpan shall file with the Commission by September 15, 2001 a summary of its incremental restructuring expenses as described above; and it is

FURTHER ORDERED, that KeySpan shall file with the Commission by April 13, 2001 a summary of its rate case expenses as described above; and it is

FURTHER ORDERED, that KeySpan shall file its revised 2001 Summer COG rates with the Commission by April 13, 2001; and it is

FURTHER ORDERED, that KeySpan's compliance filing is due May 1, 2001.

By order of the Public Utilities Commission of New Hampshire this fifth day of April, 2001.

Douglas L. Patch
Commissioner

Susan S. Geiger
Commissioner

Attested by:

Thomas B. Getz
Executive Director and Secretary

DG 00-046
NORTHERN UTILITIES, INC.

AND

DG 00-063
ENERGYNORTH NATURAL GAS, INC.

Dissenting Opinion of Commissioner Brockway

I cannot agree with the majority’s decision to approve the Settlement Agreement in these cases. The rate increases for residential and small business customers are too high and too sudden. There is no practical or theoretical reason compelling this rate redesign, and the rate increases violate longstanding principles of rate continuity and fairness.

Some rate increase for small customers and residential customers is warranted by the cost of service studies submitted by the Companies. And the Settlement Agreement will smooth the transition to the higher rates to some extent by introducing them in the summer months, when bills are typically lower. However, under traditional rate design practice, the rate increases proposed in the Settlement Agreement are simply too high, too fast. Given the 75 percent increase in the commodity cost of gas over last year, adding significant increases in base rates now would create unnecessary hardship for consumers.

Under the rate design approved by the majority today, Northern Utilities’ Residential Heating and Non-Heating classes will face overall revenue increases of 6.9 percent and 12.1 percent, respectively. In the ENGI area, the same classes will see 6 percent and 13 percent increases. Combined with large increases in customer charges, these class revenue increases will create intolerably high bill increases for small customers. A similar problem is created for small C&I customers.

Thus, over half of the residential non-heating customers of Northern Utilities will see double-digit price increases. A quarter of Northern’s residential non-heating customers will see rates go up by 20 percent or more. Almost one third of Northern’s residential heating customers will experience annual bill increases of 10 percent or greater. Half of Northern’s residential heating customers will face summer-period bill increases of 18 percent or more. While the increases for small business customers are not as dramatic, the pattern of high increases for smaller customers is similar. For example, just under half of Northern’s small business customers that have high winter gas usage will see a double-digit price increase from today’s decision to redesign gas rates.

In the case of EnergyNorth Natural Gas, the pattern of rate increases for small consumers and low-load-factor customers is similar, although the impact is more moderate. All of ENGI's residential non-heating customers will see double-digit overall bill increases. Fully three-quarters of ENGI's residential non-heating customers will see 18 percent rate hikes in their summer bills, accompanied by more moderate increases ranging from 2 percent to 10 percent in winter months. These same customers will see the non-gas portion of their summer bills go up over 40 percent, with winter non-gas rate changes highly dependent on volume of purchases (high users will see non-gas rate decreases of under 1 percent, and low volume customers will see non-gas rate increases of just under 10 percent).

The ENGI increases for residential space heating customers are considerably more modest than in the case of Northern, with half the customers seeing winter bill increases of only about 2 percent, and a quarter of these customers enjoying 3 to 4 percent bill decreases, as a result of the 23 percent decrease in base rates for this highest usage quartile of the class. Residential space heat customers in the ENGI area will see typical summer bill increases of 17 percent up to 25 percent, with non-gas cost increases of roughly 4 to 6 percent.

Again, in the case of ENGI's small business customers using high amounts of gas in the peak winter period, the pattern of increases is more moderate than in the Northern situation. About one quarter of such customers will see an 8.5 percent bill increase, and over half such customers will see a modest bill decrease as a result of the Settlement Agreement.

In both companies' cases, the steep increases to small consumers make room for decreases enjoyed by larger customers. For example, ENGI large commercial and industrial high-load-factor customers now on Rate IG are slated to receive double-digit price reductions, many larger than 25 percent. Large Commercial and Industrial customers of Northern under Rate T/G-52a will similarly rate decreases approaching 30 percent. Within the rate classes, too, larger customers will see greater reduction than smaller customers.

Again, while some reallocation of costs between big and small customers, and between low-load-factor and high-load-factor customers is warranted, the sudden and extreme shift in costs created by these Settlement Agreements cannot be justified by any principles of sound utility ratemaking.

The rate increases proposed by the utilities were influenced in part by the perceived need to lower large customers' rates in order to pave the way for greater retail gas competition. Settlement Agreements, Section IV.1. The OCA was able to insulate residential customers from most of the changes driven by the intention to facilitate greater gas competition, and this represents a significant benefit of the Settlement Agreements.

However, small commercial and industrial customers, and those with less desirable load factors, are seeing significant rate increases on a timetable driven by the impetus to introduce further gas competition. The majority in announcing its approval of these rate designs indicated the importance of gas competition to its conclusion that these revised rates should be imposed. I have recently noted my objection to the decision to introduce greater gas competition at this point, in my dissent in the gas restructuring case, Docket DE 98-124, Order No. 23,652 (March 15, 2001). Today's decision imposes heavy gas price increases on small business customers who are unlikely or unable to benefit from greater gas competition, and to this extent it is unfair. The proposed rate designs were based on the concept of allocation to class using marginal cost adjusted to allocated cost of service using the equiproportional method. This method was adopted as the cost allocation theory of the New Hampshire

Public Utilities Commission many years ago, but has never been fully implemented, and has not been reviewed during my tenure. Having studied marginal cost allocation and microeconomic pricing principles extensively in lengthy proceedings before regulatory commissions in neighboring states, as a policy matter I believe this approach to cost allocation is ill-conceived. Even if the approach were valid, the application in these cases suffers because it did not follow New Hampshire PUC precedent as to the percentage rate increases customers should experience (in a non-revenue requirements case). The approach also suffers because it posits a marginal customer cost, which is an oxymoron in non-vintage-ratemaking.

Given the lack of any compelling reason to make the rate changes proposed in these Settlement Agreements, particularly in light of the substantial increases customers have already experienced as a result of skyrocketing gas commodity prices, I believe we should either close the docket with no further rate design action, or send it back to the parties for further negotiations within specified parameters for rate continuity and fairness.

In what follows, I discuss some of the theoretical issues in somewhat more depth, and touch on some of the specific rate continuity concerns further.

1. Marginal Cost Allocation to Classes Is Not Theoretically Correct

Some economists believe that the general wellbeing of society is improved if all prices are set at the marginal cost of production. This is called the Social Welfare theory of economics. *It is not universally accepted by economists*. The theory suffers from a variety of problems. And, without going too deeply into the reasoning for the approach, it suffices to note that the theory only assumes welfare will be maximized if, among other things, income is fairly (or equally) distributed, and all goods and services are priced at marginal cost, not just the one being priced by the regulator. Neither of these two conditions holds, making it impossible to achieve the goals of the theory in practice.

Also, to the extent that marginal costs must be reconciled to accounting costs, the resulting prices will deviate from the optimal prescribed by the theory anyway, further vitiating the validity of its use. Further, marginal cost by definition describes the cost differential at infinitely small increments or decrements of load, not at the assumed increase or decrease of system load by the entire load of a class (which is the implicit assumption of an allocator based on MC). MC is a unit price, not a revenue figure. MC is more appropriately used as part of the process of setting tail block prices, so that the truly marginal use is priced closer to marginal cost.

The results of a MC allocation must be reconciled to embedded costs of service, because the rates must be set so as to allow the company to recover its entire revenue requirement. None of the methods proposed for such reconciliation, including the equiproportional method used in New Hampshire, has strong or defensible theoretical support.

Equiproportional reconciliation, for example, introduces a completely arbitrary adjustment to the unadjusted MC results (what I refer to, in my own vernacular, as “raw MC”). The size of the difference between raw MC-based revenues and average cost will vary from time to time, and the resulting extent of “distortion” of raw MC results by the equiproportional adjustment will vary as well, with no necessary relationship to the underlying social welfare theory of MC pricing. (The Ramsay Pricing method for reconciling MC revenues to total revenues, not used in New Hampshire, has its own problems, which need not be discussed here). Indeed, equiproportional reconciliation was introduced to soften the impact of the alternatives based on inverse elasticities. Once the issue of fairness and continuity are introduced as “trumping” variables, there is no theoretical basis for insisting on MC as an allocator in the first place - one might just as well use allocated cost of service, to begin with, together with the principles of fairness and continuity.

The decision to adopt MCOSS to set class revenue allocations was made in cases in the late 1980's and early 1990's, before any of the present commissioners were in office. However, the trend towards consideration of the use of MC for cost allocation that appeared in the late 1980's quickly evaporated, and now New Hampshire is one of only a few states (8-10) that use MC for class revenue allocation in any fashion at all. All the remaining states use the fully allocated COSS as the starting point for class revenue allocations.

It may be observed that the class allocations could be roughly the same if we used only the embedded cost of service studies. The OCA’s witness did not object to the methodology or results of the fully allocated cost of service studies, and no one disputed the use of an equalized rate of return benchmark. I would note that sound arguments can be made for higher required returns from riskier customers, such as large commercial and industrial customers who have the ready option of relocating or who may close their facilities in New Hampshire. Certainly in the case of Domtar, the loss of that single customer has had a noticeable impact on the earnings of Northern Utilities. Before assigning revenue requirements to classes based on allocated cost of service, the appropriate allocation of risk among classes should be explored.

I believe we should not base a cost allocation on MC unless we have examined the theory and reaffirmed it. Having said that, I could accept a rate design that was based on a MC allocator, so long as the result was consistent with a rate design based on standard rate design methods such as embedded class allocations and application of continuity, fairness, MC for informing tail-block pricing, and the like. The cost allocations in these Settlement Agreements do not pass that test.

2. "Marginal Customer Cost" Makes No Sense for Pricing Customer Charges

The Settlement Agreements were negotiated with the assumption that customer charges should approach so-called "marginal customer cost." Unless we were to introduce vintage pricing (new customers get charged something different from current customers), there is no theoretical basis for introducing the concept of marginal cost to the pricing of the customer charge. The vast majority of customers are currently on the system. Their continued presence on the system does not cause the company to incur the costs that are studied and analyzed in developing a “marginal customer cost.” Their decision to withdraw as customers would not avoid much of the marginal customer cost. The marginal customer cost is developed by analyzing the costs that would be incurred to add a new customer. I cannot accept customer charges based on this concept (unless, again, we were to charge new customers at the marginal cost, and existing customers at the embedded cost). It may be that the results of a marginal cost study and an embedded cost study would produce a similar result. That has been the case in earlier rate design cases (see, e.g. DR 90-183, Order No. 20,542, slip op. at 8). Thus, the theoretical problem may not be the key issue. Rate continuity, incentives to reduce cost, and fairness would play a larger role, then, in deciding the customer charge level. It is worth noting, however, that to the extent the invalid theory of marginal customer costs is reflected in the design of a customer charge, it will skew the design towards higher customer charges.

My other customer charge concern is that the large proposed increase in small residential and small business customer charges is a key driver of the intolerably high percentage overall price increases for these customers. One way to mitigate this effect would have been to reduce the proposed increases to customer charges. There are a number of efficiency reasons, set out in the testimony of OCA witness Ruback, why it is not sound policy to increase unduly the amount of costs a utility recovers via a fixed, flat per-customer charge.

3. Intolerably High Percentage Bill Increases for Small Consumers.

The proposal [SA at V.B] to allow overall revenue increases of 6.9 percent and 12.1 percent for Northern's Residential Heating and Non-Heating classes, respectively, and 6 percent and 13 percent for the same classes for ENGI, would create intolerably high bill increases for small customers. A similar problem is created for small C&I customers.

It would be one thing if there were a general rate increase that had to be allocated. But this is a revenue-neutral filing. The 10 percent rule the commission used in DR 91-081 (Northern General Rate Increase Case), Order No. 20,546, is too wide a range of possible increases for a revenue-neutral case, and was violated in any case here in the proposed revenue increases for the non-heating classes. By contrast, the Commission rejected a settlement in the ENGI rate design docket DR 90-183, Order No. 20,542, because in the absence of a rate increase its percentage class revenue increases were too large. The Commission sent the case back to the parties to negotiate a rate design that limited the class revenue increase to 1.25 percent for residential heating customers and 2 percent for residential non-heating customers.

Thus, the increases that the SA would permit here are higher than those previously allowed in a revenue-neutral case by several multiples.

These enormous percentage increases in class revenues then drive extremely high percentage increases in individual bills for many consumers, as noted above.

These increases are too high. They cannot be explained on the basis of esoteric economic theory. The gas restructuring decision cannot not justify these extreme rate increases.

4. Closing the Low Income Rates.

In approving the Settlement Agreement, the Commission is agreeing to close the low-income rate to further enrollment. The rationale given in the Settlement Agreement for terminating the low-income rates is odd, and unsupported by any facts in the record. The supposed rationale is that the discount gives such customers an incentive to use more. However, it is acknowledged that part of the problem may be that such customers do not have control over their usage, and live in older, draftier homes. Which is it? Are such customers wastrels, or are they caught in a situation not of their making and not within their control, that leads to hardship? There are numerous surveys of usage and end uses that could have been drawn on to illuminate these issues. Instead, the settling parties just recite conventional “wisdom” as to causality, and decide to eliminate the safety net these low-income rates provide.

I could agree that it would be preferable not to need low-income rates. However, unless residential rates generally come down to where they would produce affordable bills for low-income customers, there is no basis on this record to eliminate these rates. Rather, the SA proposes to exacerbate the conditions that make such rates necessary.

What to Do?

I believe the Commission should have determined possible limits for percentage increases in any class’s revenue responsibilities and any customer’s rates in this case, based on principles of continuity and fairness, and send the case back to the parties to continue discussions. Alternatively, in my view, we should close these dockets without setting new rates at this time.

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Nancy Brockway
Commissioner

April 5, 2001

Attested By:

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Thomas B. Getz
Executive Director & Secretary