STATE OF NEW HAMPSHIRE

PUBLIC UTILITIES COMMISSION

DG 11-069

In the Matter of:
Northern Utilities, Inc.
Petition for Permanent Rate Increase

Direct Testimony

of

Stephen P. Frink
Assistant Director – Gas & Water Division

March 26, 2012

New Hampshire Public Utilities Commission

Northern Utilities, Inc.

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Stephen P. Frink

Q. Please state your name, occupation and business address.

A. My name is Stephen P. Frink and I am employed by the New Hampshire Public Utilities Commission (Commission) as Assistant Director of the Gas & Water Division. My business address is 21 S. Fruit Street, Suite 10, Concord, New Hampshire 03301.

Q. Please summarize your educational and professional experience.

A. See ***Attachment SPF-1***.

Q. What is the purpose of your testimony in this proceeding?

A. My testimony, in conjunction with the testimonies of Staff witnesses James J. Cunningham and Robert Wyatt, provides a summary of the settlement agreement. The primary focus the Cunningham testimony is depreciation and pension costs, while the Wyatt testimony focuses on rate design.

Q. Briefly describe Northern's filing.

A. Northern requested a $3.7 million increase in its annual revenue requirement, based on a test year ending December 31, 2010, rate base as of December 31, 2010 and a return on equity of 10.5%.

In addition, the Company proposed to: implement a step adjustment in 2012 for capital investments in rate base made in calendar year 2011, with an expected revenue requirement increase of $1.4 million; implement an annual Targeted Infrastructure Recovery Adjustment (TIRA) mechanism in 2013 for rate base additions made on and after January 1, 2012 pursuant to the Company's Bare Steel Replacement program with expected revenue requirement increases of $700,000 in 2013, $1.1 million in 2014 and $1.7 million in 2015; and, implement a Dual fuel Equipment Rider to allow the Company to bill dual fuel customers (a customer that has the ability to switch from an alternate fuel to natural gas delivery service with little or no notice) for a minimum daily quantity.

The requested rate increase and step adjustment would increase annual revenues by $5,175,545, representing a 30% increase in test year delivery revenue of $17 million and 9% increase in test year total revenue (delivery and supply) of $60 million.

Q. Please describe Staff's review of the filing.

A. Staff issued three rounds of discovery, held three technical sessions and performed a comprehensive audit. All discovery responses referenced are attached in numerical order.

In performing its audit, the Commission Audit Staff issued numerous audit requests, a draft report, and a final report (issued October 18, 2011). The Company agreed to make a number of changes based on the audit report and discovery and those changes are identified and explained in the Company's supplemental responses to Staff Date Request 3-46 (Staff DR 3-46 attachments are not attached, as the changes are identified and reflected in the settlement revenue requirement schedules).

In addition, Staff closely monitored Northern's May 6, 2011 rate filing at the Maine Public Utilities Commission (MPUC Docket No. 2011-92), which reflected the same time period, shared costs and request format. See the Company's response to Staff Data Request 1-1 that compares and contrasts the Maine and New Hampshire filings.

Q. Please summarize the settlement.

A. The settlement provides for an increase in the annual revenue requirement of $3,675,150. There are three components to the increase: (i.) $2,742,525 related to the test year and effective as of the date temporary rates were implemented (August 1, 2011); (ii.) $113,806 related to 2012 pension costs and effective May 1, 2012; and, (iii.) $818,819 related to 2011 non-growth related capital investments and effective May 1, 2012 as a step adjustment. The settlement also provides for the reconciliation and recovery of bad debt write-offs related to gas costs through the cost of gas (COG) mechanism and a 12 month surcharge to recover rate case expenses and an under recovery from the reconciliation of temporary and permanent rates. The settlement does not provide for a TIRA mechanism or Dual Fuel Equipment Rider Tariff.

The $3.7 million increase effective May 1, 2012, represents a 22% increase in annual delivery revenue and a 6% increase in total year revenue (delivery and supply), with no subsequent increases absent a rate filing. See settlement revenue requirement Schedule RevReq-1-2.

Revenue Requirement

Q. How was the settlement revenue requirement calculated?

A. The revenue requirement is the total of three separate calculations. The first calculation is based on an adjusted 2010 test year and known and measurable changes in revenues and expense during the 12 months following the test year. The second calculation is based on 2012 pension related costs. The third calculation is related to 2011 non-growth related capital investment.

Q. Please describe the revenue requirement related to the test year.

A. The settlement revenue requirement increase related to the test year is $2,742,525 based on year end rate base of $69,562,393, an overall rate of return of 7.24% and pro formed test year income of $3,380,106. This revenue requirement increase will be reflected in rates effective May 1, 2012 and reconciled to temporary rates that went into effect August 1, 2011.

Q. Please describe the revenue requirement related to the 2012 pension costs.

A. The settlement revenue requirement increase related to the 2012 pension costs is $113,806. The derivation of this adjustment is explained in the testimony of Mr. Cunningham. This revenue increase will be reflected in rates effective May 1, 2012 and will not be reconciled with temporary rates.

Q. Please describe the revenue requirement related to 2011 non-growth capital investment.

A. The settlement revenue requirement increase related to 2011 non-growth capital investment is $818,819. The settlement provides for a return on 2011 non-growth capital investments of $6,337,000, adjusted for depreciation and deferred income taxes, and provides for the recovery of the related annual depreciation expense. This revenue increase will be reflected in rates effective May 1, 2012 and will not be reconciled with temporary rates.

Q. Please explain how settlement revenue requirement schedules were developed.

A. The settlement schedules are the original Northern schedules revised to reflect Northern updates and settlement positions. All adjustments are identified in the settlement revenue requirement schedules, along with supporting schedules.

Q. Are detailed explanations of the adjustments provided elsewhere?

A. Yes. The majority of the adjustments are explained in the testimony of Mr. Chong and most of the subsequent changes are explained in the Company's supplemental responses to Staff Data Request 3-46, in which Northern updated and revised its original revenue requirement schedules.

Adjustments not explained in Northern's initial filing, its responses to Staff DR 3-46, or Mr. Cunningham's testimony are explained below. My testimony also summarizes the most significant adjustments made by Northern post-filing.

<u>Rate Base Adjustments</u>

Q. Please summarize the rate base adjustments Northern made in its updated and revised revenue requirement calculation provide in response to Staff DR 3-46.

A. Northern incorporated the results of its lead/lag study and removed the accrued revenue portion of Net Operating Losses (NOL) in calculating deferred income taxes. The lead/lag study decreased cash working capital by $1,048,927 and removing the accrued revenue portion of the NOL reduced accumulated deferred income tax by $1,599,333. The combined impact is a $2,648,260 reduction in rate base.

Q. Why is accrued revenue excluded in the Net Operating Loss calculation?

A. A significant portion of the NOL resulted from gas costs exceeding gas revenues on December 31, 2010, a timing difference that reversed very quickly. Therefore, the settlement excludes accrued revenue from the NOL calculation, consistent with how that timing difference was treated in calculating Northern's cash working capital requirement.

Q. Are there rate base adjustments other than those explained above?

A. Yes, there are changes related to depreciation and pension that impact rate base and are explained in Mr. Cunningham's testimony.

Revenue & Expense Adjustments

Q. Please identify revenue and expense adjustments made to the initial filing that exceed $100,000.

A. There are no changes to test year revenues that exceed $100,000 and only three such adjustments to test year expenses. The expense adjustments exceeding $100,000 are a $519,282 increase in the property tax, a $221,091 net reduction as a result of the Staff Audit Report, and a reduction of $147, 687 related to the regulatory commission assessment expense.

Q. Please explain the increase in property tax.

A. The adjustment is based on Northern's actual 2011 property tax bills, a much greater increase than Northern anticipated in its initial filing.

Q. Please explain the net decrease as result of the Staff Audit Report.

A. There are a large number of adjustments identified in the Audit Report, none of which exceed $100,000. The findings that had the largest cumulative impact are 2009 expenses booked in 2010, removing the 2009 expenses reduced test year expenses by $92,828. The supporting schedule can be found in settlement revenue requirement Schedule RevReq-3-Audit.

Q. Please explain the decrease in the regulatory commission assessment expense.

A. The Commission is primarily funded by an assessment on the utilities it regulates. Historically, the natural gas utilities have included that cost in test year expenses for recovery through delivery rates.

The Commission regulates both delivery and supply rates and, therefore, it is appropriate to recognize a portion of that expense as a supply cost to be recovered through the cost of gas mechanism. The settlement provides for recovery of a portion of Northern's annual PUC assessment expense through the Local Distribution Adjustment Charge (LDAC), to be set in the winter COG proceeding. Such treatment is consistent with how the electric utilities recover the annual PUC assessment expense.

Accordingly, the test year expense has been reduced for the amount that would have been recovered through the cost of gas if the new policy had been in effect during the test year.

Q. Please explain any revenue or expense adjustments not explained in either Northern's initial filing or updated schedules.

A. In addition to the changes in depreciation and pension expenses explained in Mr. Cunningham's testimony, there are three other expense adjustments not explained by Northern in its initial or updated schedules. Those changes are a $21,865 reduction in the office lease expense, a $60,002 reduction in the integrated resource planning expense and $4,397 increase in environmental remediation expense.

Q. Please explain the office lease expense adjustment.

A. Northern's headquarters lease expense includes a 12% rate of return on equity to an affiliate company. The settlement provides for a return on equity of 9.5%, reducing the test year lease expense by $21,865. The supporting schedule can be found in the settlement revenue requirement Schedule RevReq-3-Liberty Lane.

Q. Please explain the integrated resource planning expense adjustment.

A. New Hampshire's natural gas utilities file integrated resource plans (IRP) periodically, typically every three years with a five year planning horizon. Therefore, the 2010 IRP expense of $90,003 is being amortized over three years, reducing the test year expense by $60,002. The supporting schedule can be found in settlement revenue requirement Schedule RevReq-3-IRP.

Q. Please explained the environmental remediation expense adjustment.

A. While there is a mechanism under which one-time environmental remediation expenses are recovered through the LDAC, there are certain recurring environmental remediation expenses, such as on-going testing and monitoring of remedied sites, not recovered through the LDAC. The test year environmental remediation costs not eligible for recovery through the LDAC have been normalized by taking the annual average of those costs for calendar years 2010 and 2011. The supporting schedule can be found in settlement revenue requirement Schedule RevReq-3-ERC.

<u>Rate of Return</u>

Q. Please explain the rate of return calculation.

A. The rate of return calculation uses the same capital structure and debt costs as reflected in Northern's initial filing but provides for a 9.5% return on equity, rather than the 10.5% return on equity proposed by the Company.

Q. Is 9.5% a fair and reasonable return on equity?

A. Yes, although slightly lower than the 9.67% granted in Northern last rate case (DG 01-182) and lower than the 10.5% proposed by Northern, 9.5% is consistent with recent Commission returns in approved settlements and almost identical to the 9.54% the Commission approved in the most recent rate proceeding in which the return on equity was litigated (*EnergyNorth Natural Gas, Inc. D/B/A National Grid NH,* Order No. 24,972 dated May 29, 2009).

Step Adjustment for 2011 Non-growth Capital Investments

Q. How was the revenue requirement for 2011 non-growth capital investment calculated?

A. As previously stated, the settlement provides for a return on 2011 non-growth capital investment of $6,337,000 and annual depreciation. The non-growth capital investment was determined by multiplying the total 2011 capital investments by the percentage of the 2011 non-growth capital budget amount divided by the 2011 total capital budget amount.

Q. Why was the 2011 capital budget used to determine 2011 non-growth capital investment?

A. Settlement discussions took place in late 2011 and early 2012 and the Company was still in the process of closing its 2011 books and had not had the opportunity to analyze and categorize its 2011 capital investments, therefore the 2011 budget was used to calculate a reasonable proxy. Actual 2011 non-growth capital investments may be greater or less than that determined by using the 2011 capital budget, although the settlement does not provide a true-up of those investments based on a final analysis of 2011 capital investments.

The Company provided schedules of its 2011 capital investments to the Commission Audit Staff which then conducted an audit to ensure the capital projects were properly accounted for and placed in service during 2011. The Audit Staff issued a final report on March 23, 2011 that found that the 2011 capital investments detailed in the original schedules were overstated by approximately $300,000. The Company agreed with the finding and the step adjustment for 2011 non-growth capital investment reflects the adjusted total.

<u>Targeted Infrastructure Recovery Adjustment</u>

Q. Please summarize the Company's TIRA mechanism proposal.

A. The Company's TIRA proposal was for a series of step adjustments to recover its continuing investments in bare steel replacements and associated system enhancements.

Q. Has the Commission approved such a mechanism for natural gas utilities in the past?

A. Yes, Order No. 20,546 (October 30, 1992) approved such a mechanism for Northern and Order No. 24,777 (July 12, 2007) provided a similar mechanism for EnergyNorth Natural Gas, Inc. D/B/A National Grid NH (EnergyNorth).

Q. What were the circumstances that lead to implementation of those mechanisms?

A. Natural gas utilities replace high risk pipe as a normal course of business and New Hampshire's natural gas utilities have had pipe replacement programs for many years. Back in the 1990's Northern had a great deal of high risk pipe on its system which posed a significant threat to public safety, therefore a mechanism was established to encourage Northern to accelerate replacement. The Company's annual reporting on its Bare Steel Replacement Program indicated that the program was working as intended and that the public safety risk had been greatly reduced over the course of the program. Order No. 23,576 (October 30, 2000) approved discontinuance of the recovery mechanism but continuation of the program and program reporting. As a condition of the acquisition settlement approved by the Commission in 2008 Northern agreed to complete its Bare Steel Replacement Program within nine years.

The Commission approved a recovery mechanism in 2007 for EnergyNorth's Cast Iron/Bare Steel replacement program as an incentive for EnergyNorth to accelerate its program. Absent the accelerated program EnergyNorth's Cast Iron/Bare Steel replacement would not be complete for several decades and even with the accelerated program may not be completed for another twenty years. Also, the EnergyNorth recovery mechanism differs from the prior and proposed Northern recovery mechanisms, as EnergyNorth is required to spend a minimum of $500,000 per year on its Cast Iron/Bare Steel Program and that investment is not recovered through the mechanism.

Q. Why is the proposed TIRA mechanism not being implemented at this time?

A. As previously stated, gas utilities replace high risk pipe as a normal course of business and absent a compelling need for an accelerated program a special rate recovery mechanism for those investments is not necessary and better left for a general rate case. There are also two other reasons why such a mechanism would not appropriate for Northern at this time. First, Northern is not proposing an accelerated program nor is there a compelling need for an accelerated program, as the program is expected to be completed in a reasonable period of time. Second, there will only be a limited delay in recovery of those investments, as the program costs for 2011 are reflected in the step adjustment and there is a strong likelihood that Northern will be filing a general rate case in 2014.

Q. Why does Staff expect Northern to file a rate case in 2014?

A. When Unitil acquired Northern it refinanced $60 million of existing long-term debt. The retired debt had an interest rate of 4.80%, whereas the interest rate on the new notes is 6.95%

(ten year maturity) and 7.72% (thirty year maturity). As a condition of the acquisition settlement Northern agreed to use a stipulated long-term debt cost in future rate cases that reflect the cost of the retired debt until such time as that debt would have matured. In this proceeding Northern's stipulated long-term debt cost is 5.81% compared to an actual long-term debt cost of 7.06%. Being able to reflect its actual long-term debt cost will be a strong incentive for Northern to file a new rate case when that condition of the acquisition settlement expires in 2013.

<u>Dual Fuel Rider</u>

Q. Why is Northern's Dual Fuel Rider proposal being withdrawn?

A. It is unclear to what extent, if any, dual fuel customers may be contributing to distribution capacity constraints. At this time it appears there is only one instance where Northern's distribution capacity is constrained due to reserving capacity for a dual fuel customer. This issue needs to be explored further and once that analysis is completed the Company may file a new proposal designed to ensure appropriate compensation from that/those customer(s).

<u>Recovery of Bad Debt Related to Gas Costs</u>

Q. How is bad debt related to gas costs currently being treated?

A. The bad debt percentage as determined in the last delivery rate case is applied to annual gas costs and recovered through the COG. Actual bad debt experience varies from year to year but the bad debt percentages applied to supply costs do not.

Q. How will bad debt write-offs related to supply costs be treated per the settlement?

A. Actual annual bad debt write offs related to supply costs will now be recovered through the COG mechanism, rather than using a fixed percentage applied to annual supply costs.

Q. Is it appropriate for the Company to recover the commodity related portion of its uncollectible accounts expense on a fully reconciling basis?

A. To the extent accounts written off as uncollectible are beyond the Company's control it is appropriate to allow the Company to recover its actual supply related bad debt expense through the cost of gas mechanism. The Company has no opportunity to earn a profit on commodity sales and recovery per the terms of the settlement ensures the Company is not at risk for non-collection of commodity-related revenue and that rate payers do not pay more than the actual commodity related bad debt write-offs.

<u>Rate Case Expense & Temporary/Permanent Rate Reconciliation</u>

Q. What is the estimated rate case expense?

A. The estimated rate case expense is approximately $300,000. The Company provided the Commission Audit Staff with supporting schedules and invoices for rate case expenses through February 29, 2012 and a Final Audit Report which found no exceptions was issued on March 12, 2012.

Q. What is the estimated under recovery from the reconciliation of temporary and permanent rates?

A. The estimate under recovery is approximately $750,000.

Q. How are those costs to be recovered?

A. The costs will be recovered through a twelve month volumetric surcharge commencing on service rendered May 1, 2012. Based on the estimated expense and under recovery the volumetric rate applicable to all classes should be less than two cents per therm.

Q. Will the actual rate case expense and reconciliation under collection be reconciled with the surcharge revenues?

A. Yes, actual expenses and the under recovery will be reconciled with the surcharge revenues at the end of the surcharge period and filed no later than July 31, 2013.

__Summary__

Q. Please summarize how the settlement is in the public interest?

A. While a 6% increase in rates is substantial, it is worth noting that it has been ten years since Northern's last increase. Furthermore, the settlement does not provide for multiple rate increases as was proposed by Northern and delivery rates are likely to remain constant through 2013. The acquisition settlement provision requiring Northern to use a stipulate rate of return expires in 2013, and while that condition serves as an incentive for Northern to file a general rate case at that time, it also serves as a disincentive for Northern to file one prior to that time. And while a longer period between rate cases may be preferable, it is less of a concern if rate case expenses are limited as was the case in this proceeding. The expected rate case expense of approximately $300,000 is half of the almost $600,000 Northern projected in its initial filing and compares favorably with the $500,000 of rate case expenses incurred by Northern in its prior rate case (DG 01-182).

Q. Does that conclude your testimony?

A. Yes.