North Shore Gas Company

Comparison of Prior Forecasts to Actual Data
Income Statement

Historical Year Ended December 31, 2010

Line No.	Description	Actual	Budget	Actual vs. Budget	Percentage Variation Actual vs. Budget	Line No.
	[A]	[B]	[C]	[D]	[E]	
1	Operating Revenues	$ 211,260,000	$ 247,809,000	$ (36,549,000)	(14.7%)	1
2	Operating Expenses:					2
3	Cost of Gas	126,414,000	160,895,000	(34,481,000)	(21.4%)	3
4	Other Operation and Maintenance	55,351,000	56,015,000	(664,000)	(1.2%)	4
5	Depreciation Expense	9,037,000	9,287,000	(250,000)	(2.7%)	5
6	Amortization of Other Limited Term Gas Plant	-	-	-	-	6
7	Taxes Other Than Income	3,105,000	2,759,000	346,000	12.5%	7
8	Federal Income Taxes-Current	(3,107,000)	3,554,000	(6,661,000)	(187.4%)	8
9	State Income Taxes-Current	(426,000)	425,000	(851,000)	(200.2%)	9
10	Deferred Income Taxes	9,308,000	1,495,000	7,813,000	522.6%	10
11	Investment Tax Credit	(48,000)	13,000	(61,000)	(469.2%)	11
12	Total Operating Expenses	199,634,000	234,443,000	(34,809,000)	(14.8%)	12
13	Operating Income	11,626,000	13,366,000	(1,740,000)	(13.0%)	13
14	Income from Utility Plant Leased to Others	-	-	-	-	14
15	Utility Operating Income	11,626,000	13,366,000	(1,740,000)	(13.0%)	15
16	Other Income, Net of Income Deductions	497,000	224,000	273,000	121.9%	16
17	Income Before Interest Charges	12,123,000	13,590,000	(1,467,000)	(10.8%)	17
18	Interest Charges	4,196,000	4,330,000	(134,000)	(3.1%)	18
19	Net Income	$ 7,927,000	$ 9,260,000	$ (1,333,000)	(14.4%)	19

North Shore Gas Company

Comparison of Prior Forecasts to Actual Data
Income Statement

Historical Year Ended December 31, 2011

Line No.	Description	Actual	Budget	Actual vs. Budget	Percentage Variation Actual vs. Budget	Line No.
	[A]	[B]	[C]	[D]	[E]	
1	Operating Revenues	$ 201,423,000	$ 232,921,000	$ (31,498,000)	(13.5%)	1
2	Operating Expenses:					2
3	Cost of Gas	117,426,000	142,247,000	(24,821,000)	(17.4%)	3
4	Other Operation and Maintenance	51,780,000	58,384,000	(6,604,000)	(11.3%)	4
5	Depreciation Expense	9,508,000	9,550,000	(42,000)	(0.4%)	5
6	Amortization of Other Limited Term Gas Plant	-	-	-	-	6
7	Taxes Other Than Income	2,940,000	2,948,000	(8,000)	(0.3%)	7
8	Federal Income Taxes-Current	2,672,000	4,459,000	(1,787,000)	(40.1%)	8
9	State Income Taxes-Current	1,559,000	510,000	1,049,000	205.7%	9
10	Deferred Income Taxes	1,552,000	1,088,000	464,000	42.6%	10
11	Investment Tax Credit	(41,000)	(37,000)	(4,000)	10.8%	11
12	Total Operating Expenses	187,396,000	219,149,000	(31,753,000)	(14.5%)	12
13	Operating Income	14,027,000	13,772,000	255,000	1.9%	13
14	Income from Utility Plant Leased to Others	-	-	-	-	14
15	Utility Operating Income	14,027,000	13,772,000	255,000	1.9%	15
16	Other Income, Net of Income Deductions	(85,000)	406,000	(491,000)	(120.9%)	16
17	Income Before Interest Charges	13,942,000	14,178,000	(236,000)	(1.7%)	17
18	Interest Charges	4,213,000	4,342,000	(129,000)	(3.0%)	18
19	Net Income	$ 9,729,000	$ 9,836,000	$ (107,000)	(1.1%)	19

North Shore Gas Company

Comparison of Prior Forecasts to Actual Data
Income Statement

Historical Year Ended December 31, 2012

Line No.	Description	Actual	Budget	Actual vs. Budget	Percentage Variation Actual vs. Budget	Line No.
	[A]	[B]	[C]	[D]	[E]	
1	Operating Revenues	$ 162,358,000	$ 216,762,000	$ (54,404,000)	(25.1%)	1
2	Operating Expenses:					2
3	Cost of Gas	83,575,000	125,538,000	(41,963,000)	(33.4%)	3
4	Other Operation and Maintenance	47,964,000	58,694,000	(10,730,000)	(18.3%)	4
5	Depreciation Expense	9,908,000	10,190,000	(282,000)	(2.8%)	5
6	Amortization of Other Limited Term Gas Plant	-	-	-	-	6
7	Taxes Other Than Income	3,016,000	3,149,000	(133,000)	(4.2%)	7
8	Federal Income Taxes-Current	(3,282,000)	(1,082,000)	(2,200,000)	203.3%	8
9	State Income Taxes-Current	(557,000)	572,000	(1,129,000)	(197.4%)	9
10	Deferred Income Taxes	9,655,000	6,452,000	3,203,000	49.6%	10
11	Investment Tax Credit	(27,000)	43,000	(70,000)	(162.8%)	11
12	Total Operating Expenses	150,252,000	203,556,000	(53,304,000)	(26.2%)	12
13	Operating Income	12,106,000	13,206,000	(1,100,000)	(8.3%)	13
14	Income from Utility Plant Leased to Others	-	-	-	-	14
15	Utility Operating Income	12,106,000	13,206,000	(1,100,000)	(8.3%)	15
16	Other Income, Net of Income Deductions	(62,000)	225,000	(287,000)	(127.6%)	16
17	Income Before Interest Charges	12,044,000	13,431,000	(1,387,000)	(10.3%)	17
18	Interest Charges	3,785,000	4,348,000	(563,000)	(12.9%)	18
19	Net Income	$ 8,259,000	$ 9,083,000	$ (824,000)	(9.1%)	19

North Shore Gas Company

Statement from the Independent Certified Public Accountant

Deloitte.

Deloitte & Touche LLP
111 S. Wacker Drive
Chicago, IL 60606-4301
USA

Tel: +1 312 486 1000
Fax: +1 312 486 1486
www.deloitte.com

INDEPENDENT ACCOUNTANT'S REPORT

To the Board of Directors
North Shore Gas Company

We have examined the accompanying forecasted balance sheet, statements of income, retained earnings, and cash flows of North Shore Gas Company (the "Company") as of December 31, 2015, and for the year then ending. The Company's management is responsible for the forecast. Our responsibility is to express an opinion on the forecast based on our examination.

Our examination was conducted in accordance with attestation standards established by the American Institute of Certified Public Accountants and, accordingly, included such procedures as we considered necessary to evaluate both the assumptions used by management and the preparation and presentation of the forecast. We believe that our examination provides a reasonable basis for our opinion.

In our opinion, the accompanying forecast is presented in conformity with the guidelines for presentation of a forecast established by the American Institute of Certified Public Accountants, and the underlying assumptions provide a reasonable basis for management's forecast. However, there will usually be differences between the forecasted and actual results, because events and circumstances frequently do not occur as expected, and those differences may be material. We have no responsibility to update this report for events and circumstances occurring after the date of this report.

This report is intended solely for the information and use of the Board of Directors and management of the Company for filing with the Illinois Commerce Commission in connection with the Company's proposed general increase in rates and is not intended and should not be used by anyone other than these specified parties.

Deloitte & Touche LLP

February 24, 2014

NORTH SHORE GAS COMPANY

FORECASTED STATEMENT OF INCOME (Millions)	Year Ended December 31, 2015
Natural gas operating revenues	**$206.0**
Operating expenses	
Natural gas purchased for resale	**104.9**
Operating and maintenance expense	**70.4**
Depreciation and amortization expense	**11.8**
Taxes other than income taxes	**2.7**
Operating income	**16.2**
Miscellaneous income	**0.3**
Interest expense	**(3.7)**
Other expense	**(3.4)**
Income before taxes	**12.8**
Provision for income taxes	**4.9**
Net income	**$7.9**

The accompanying Summary of Significant Accounting Policies and Assumptions are an integral part of these statements.

NORTH SHORE GAS COMPANY

FORECASTED BALANCE SHEET (Millions)	**December 31, 2015**
Assets	
Accounts receivable and accrued unbilled revenues, net of reserves of $1.5	**$34.5**
Inventories:	
Natural gas in storage, primarily at LIFO	**9.7**
Materials and suppplies	**1.3**
Regulatory assets	**2.9**
Other current assets	**0.5**
Current assets	**48.9**
Property, plant, and equipment, net of accumulated depreciation of $196.0	**318.1**
Regulatory assets	**79.2**
Other long-term assets	**0.5**
Total assets	**$446.7**
Liabilities and Shareholder's Equity	
Accounts payable	**$16.5**
Payables to related parties	**4.5**
Notes payable to related parties	**41.1**
Accrued taxes	**4.9**
Customer credit balances	**4.4**
Other current liabilities	**9.4**
Current liabilities	**80.8**
Long-term debt	**82.0**
Deferred income taxes	**80.9**
Deferred investment tax credits	**2.6**
Environmental remediation liabilities	**51.6**
Pension and other postretirement benefit obligations	**14.4**
Asset retirement obligations	**20.5**
Other long-term liabilities	**12.2**
Long-term liabilities	**264.2**
Commitments and contingencies	
Common stock, without par value	**25.0**
Retained earnings	**76.7**
Total liabilities and shareholder's equity	**$446.7**

The accompanying Summary of Significant Accounting Policies and Assumptions are an integral part of these statements.

NORTH SHORE GAS COMPANY

FORECASTED STATEMENT OF CASH FLOWS (Millions)	Year Ended December 31, 2015
Operating Activities:	
Net Income	**$7.9**
Adjustments to reconcile net income to cash provided by (used in) operations:	
Depreciation and amortization expense	**11.8**
Bad debt expense	**1.4**
Deferred income taxes and investment tax credits- net	**(2.9)**
Pension and postretirement expense	**3.7**
Pension and postretirement funding	**(4.8)**
Recoveries and refunds of other regulatory assets and liabilities	**2.4**
Other, net	**(0.3)**
Net changes in working capital	**6.3**
Net cash provided by operating activities	**25.5**
Investing Activities:	
Capital expenditures	**(28.1)**
Net cash used for investing activities	**(28.1)**
Financing Activities:	
Intercompany loan payable	**2.6**
Net cash provided by financing activities	**2.6**
Net increase in cash and cash equivalents	**-**
Cash and cash equivalents at beginning of year	**0.0**
Cash and cash equivalents at end of year	**0.0**

The accompanying Summary of Significant Accounting Policies and Assumptions are an integral part of these statements.

NORTH SHORE GAS COMPANY

FORECASTED STATEMENT OF RETAINED EARNINGS (Millions)	December 31, 2015
Account 21600 Unappropriated Retained Earnings	
Balance at beginning of year	**$68.8**
Add:	
Net income	**7.9**
Less:	
Common stock dividends declared	**-**
Balance at end of year	**$76.7**

The accompanying Summary of Significant Accounting Policies and Assumptions are an integral part of these statements.

North Shore Gas Company

Summary of Significant Accounting Policies and Assumptions

Used in the Forecast For the Year Ending December 31, 2015

PRESENTATION BASIS

The financial forecast has been prepared by North Shore Gas Company (“the Company” or “NSG”) and presented in accordance with the guidelines established in the November 1, 2012 AICPA Prospective Financial Information Guide. This financial forecast presents, to the best of management's knowledge and belief, the Company's expected financial position, results of operations, retained earnings and cash flows for the forecast period. Accordingly, the forecast reflects management’s judgment as of July 31, 2013, the date of this forecast, of the expected conditions and management’s expected course of action. Final approval of the financial forecast was in December 2013. The assumptions disclosed herein are those that management believes are significant to the forecast. There will usually be differences between the forecasted and actual results, because events and circumstances frequently do not occur as expected, and those differences may be material.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The accounting policies used in preparing the forecast are below and are the same as in the Company’s audited financial statements.

I. Nature of Operations

NSG is a regulated natural gas utility company that purchases, stores, distributes, sells, and transports natural gas to customers in the northern suburbs of Chicago. NSG is subject to the jurisdiction of, and regulation by, the Illinois Commerce Commission (“ICC”), which has general supervisory and regulatory powers over public utilities in Illinois, and the Federal Energy Regulatory Commission (“FERC”), which regulates the interstate services NSG provides. The term "utility" refers to NSG’s regulated activities.

As used in these notes, the term “financial statements” includes the statement of income, balance sheet, retained earnings and statement of cash flows, unless otherwise noted.

II. Use of Estimates

NSG prepares its financial statements in conformity with accounting principles generally accepted in the United States of America (“GAAP”). NSG makes estimates and assumptions that affect assets, liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements. Actual results may differ from these estimates.

III. Cash and Cash Equivalents

Short-term investments with an original maturity of three months or less are reported as cash equivalents.

IV. Revenues and Customer Receivables

Revenues related to the sale of natural gas are recognized when service is provided or natural gas is delivered to customers. NSG also accrues estimated amounts of revenues for services provided or natural gas delivered but not yet billed to customers. Estimated unbilled revenues are calculated using a variety of judgments and assumptions related to customer class, contracted rates, weather, and customer use. NSG presents revenues net of pass-through taxes on the income statements.

NSG has various revenue and cost recovery adjustment mechanisms in place that currently provide for the recovery of prudently incurred costs and baseline revenue amounts. A summary of the significant adjustment mechanisms which are included in rates follows:

- A one-for-one recovery mechanism for natural gas commodity and capacity costs.
- Riders for cost recovery for both environmental cleanup and energy efficiency and on-bill financing program costs.
- A rider for cost recovery or refund of uncollectible accounts expense based on the difference between actual net write-offs and the amount allowed in rates (as defined in the latest rate order) as well as amounts recovered under Rider UEA-GC (Uncollectible Expense Adjustment – Gas Costs).
- A Volume Balancing Adjustment (Rider VBA) decoupling mechanism, which allows NSG to bill adjustments going forward to recover or refund the differences between the actual and authorized distribution margin for its residential and general service rate classes. In the first quarter of 2013, the Illinois Appellate Court affirmed the ICC's authority to approve a permanent decoupling mechanism and therefore, NSG assumes in this forecast that it will continue to file these adjustments with the ICC for the recovery/refund of amounts recorded related to decoupling. In June 2013, the Illinois Attorney General and Citizens Utility Board petitioned the Illinois Supreme Court to appeal the Court's decision. The Illinois Supreme Court granted the request in September 2013. The Illinois Supreme Court has no deadline by which it must act.

V. Inventories

Inventories consist of materials and supplies, natural gas in storage, and liquid propane. Materials and supplies and liquid propane inventory are priced at average cost. NSG prices natural gas storage injections at the calendar year average of the costs of natural gas supply purchased. Withdrawals from storage are priced on the LIFO cost method.

VI. Risk Management Activities

As part of NSG's regular operations, NSG enters into contracts, including options, forwards, and swaps, to manage changes in commodity prices.

All derivatives are recognized on the balance sheets at their fair value unless they are designated as and qualify for the normal purchases and sales exception. NSG continually assesses its contracts designated as normal and will discontinue the treatment of these contracts as normal if the required criteria are no longer met. NSG's tariffs allow for full recovery from its customers of prudently incurred natural gas supply costs, including gains or losses on these derivative instruments. These derivatives are marked to fair value; the resulting risk management assets are offset with regulatory liabilities or decreases to regulatory assets, and risk management liabilities are offset with regulatory assets or decreases to regulatory liabilities. Management believes any gains or losses resulting from the eventual settlement of these derivative instruments will be refunded to or collected from customers in rates.

NSG has risk management contracts with various counterparties. NSG monitors credit exposure levels and the financial condition of its counterparties on a continuous basis to minimize credit risk.

VII. Property, Plant, and Equipment

Utility plant is stated at cost, including any associated allowance for funds used during construction and asset retirement costs. The costs of renewals and betterments of units of property (as distinguished from minor items of property) are capitalized as additions to the utility plant accounts. Maintenance, repair, replacement, and renewal costs associated with items not qualifying as units of property are considered operating expenses. NSG records a regulatory liability for cost of removal accruals, which are included in rates. Actual removal costs are charged against the regulatory liability as incurred. Except for land, no gains or losses are recognized in connection with ordinary retirements of utility property units. NSG charges the cost of units of property retired, sold, or otherwise disposed of, less salvage value, to accumulated depreciation.

NSG records straight-line depreciation expense over the estimated useful life of utility property, using depreciation rates as approved by the ICC. The provision for depreciation, expressed as an annual percentage of the original cost of depreciable property, is 2.5% for the forecasted year ending December 31, 2015.

VIII. Regulatory Assets and Liabilities

Regulatory assets represent probable future revenue associated with certain costs or liabilities that have been deferred and are expected to be recovered from customers through the ratemaking process. Regulatory liabilities represent amounts that are expected to be refunded to customers in future rates or amounts collected in rates for future costs. If at any reporting date a previously recorded regulatory asset is no longer probable of recovery, the regulatory asset is reduced to the amount considered probable of recovery with the reduction charged to expense in the year the determination is made.

IX. Retirement of Debt

Any call premiums or unamortized expenses associated with refinancing utility debt obligations are amortized consistent with regulatory treatment of those items. Any gains or losses resulting from the retirement of utility debt that is not refinanced are amortized over the remaining life of the original debt.

X. Asset Retirement Obligations

NSG recognizes at fair value legal obligations associated with the retirement of tangible long-lived assets that result from the acquisition, construction or development, and/or normal operation of the assets. A liability is recorded for these obligations as long as the fair value can be reasonably estimated, even if the timing or method of settling the obligation is unknown. The asset retirement obligations are accreted using a credit-adjusted risk-free interest rate commensurate with the expected settlement dates of the asset retirement obligations; this rate is determined at the date the obligation is incurred. The associated retirement costs are capitalized as part of the related long-lived assets and are depreciated over the useful lives of the assets. Subsequent changes resulting from revisions to the timing or the amount of the original estimate of undiscounted cash flows are recognized as an increase or a decrease in the carrying amount of the liability and the associated retirement cost.

XI. Income Taxes

NSG is included in the consolidated United States income tax return filed by Integrys Energy Group. NSG is party to a federal and state tax allocation arrangement with Integrys Energy Group and its subsidiaries under which each entity determines its provision for income taxes on a stand-alone basis. NSG settles the intercompany income taxes payable at the time that payments are made to the applicable taxing authority.

Deferred income taxes have been recorded to recognize the expected future tax consequences of events that have been included in the financial statements by using currently enacted tax rates for the differences between the income tax basis of assets and liabilities and the basis reported in the financial statements. NSG records valuation allowances for deferred income tax assets unless it is more likely than not that the benefit will be realized in the future. NSG defers certain adjustments made to income taxes that will impact future rates and records regulatory assets or liabilities related to these adjustments.

NSG uses the deferral method of accounting for investment tax credits (ITCs). Under this method, NSG records the ITCs as deferred credits and amortizes such credits as a reduction to the provision for income taxes over the life of the asset that generated the ITCs. ITCs that do not reduce income taxes payable for the current year are eligible for carryover and recognized as a deferred income tax asset.

NSG reports interest and penalties accrued related to income taxes as a component of provision for income taxes in the income statements.

XII. Employee Benefits

The costs of pension and other postretirement benefits are expensed over the periods during which employees render service. Effective with new rates implemented in 2010, NSG began reflecting pension and other postretirement benefit costs in rates using Integrys Energy Group's basis in the related plan assets and obligations and method of determining these costs, which Integrys Energy Group established at the time of the February 2007 Peoples Energy, LLC ("PELLC") merger. In addition, the cumulative difference between NSG's accounting basis and the accounting basis of Integrys Energy Group in NSG's pension and postretirement benefit obligations is being amortized as a component of NSG's rates over the average remaining service lives of the participating employees. In computing the expected return on pension plan assets, a market-related value of plan assets is used that recognizes differences between actual investment returns and the expected return on plan assets over the subsequent five years. NSG's regulators allow recovery in rates for the net periodic benefit cost calculated under GAAP.

NSG recognizes the funded status of defined benefit postretirement plans on the balance sheet, and recognizes changes in the plans' funded status in the year in which the changes occur. NSG records changes in the funded status to regulatory asset or liability accounts, pursuant to the Regulated Operations Topic of the FASB ASC.

NSG accounts for its participation in benefit plans sponsored by Integrys Business Support, LLC ("IBS") and PELLC as multiple employer plans. Under affiliate agreements, NSG is responsible for its share of plan costs and obligations and is entitled to its share of plan assets; accordingly, NSG accounts for its pro rata share of the IBS and PELLC plans as its own plans.

XIII. Fair Value

A fair value measurement is required to reflect the assumptions market participants would use in pricing an asset or liability based on the best available information. These assumptions include the risks inherent in a particular valuation technique (such as a pricing model) and the risks inherent in the inputs to the model.

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). NSG uses a mid-market pricing convention (the mid-point price between bid and ask prices) as a practical measure for valuing the majority of its derivative assets and liabilities.

Fair value accounting rules provide a hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). The three levels of the fair value hierarchy are defined as follows:

Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 – Pricing inputs are observable, either directly or indirectly, but are not quoted prices included within Level 1. Level 2 includes those financial instruments that are valued using external inputs within models or other valuation methodologies.

Level 3 – Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value.

Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement.

NSG determines fair value using a market-based approach that uses observable market inputs where available, and internally developed inputs where observable market data is not readily available. For the unobservable inputs, consideration is given to the assumptions that market participants would use in valuing the asset or liability. These factors include not only the credit standing of the counterparties involved, but also the impact of NSG’s nonperformance risk on its liabilities.

When possible, NSG bases the valuations of its risk management assets and liabilities on quoted prices for identical assets in active markets. These valuations are classified in Level 1. The valuations of certain contracts include inputs related to market price risk (commodity or interest rate), price volatility (for option contracts), price correlation (for cross commodity contracts), probability of default, and time value. These inputs are available through multiple sources, including brokers and over-the-counter and online exchanges. Transactions valued using these inputs are classified in Level 2. Transactions classified in Level 3 include significant inputs that are generally less observable from objective sources and/or are used with internally developed methodologies to calculate management’s best estimate of fair value. At this time, NSG does not have any Level 3 fair value measurements.

SUMMARY OF SIGNIFICANT ASSUMPTIONS

I. Operating Revenues

1. Forecasted revenues were primarily determined by applying the Company’s current rates and rate structure to forecasted deliveries of gas to customers, plus the forecasted cost of gas delivered, environmental recovery charges, Energy Efficiency and On-Bill Financing Adjustment (“Rider EOA”) charges, the Rider VBA adjustments and other miscellaneous charges and adjustments.

2. Forecasted deliveries, including changes due to customer growth and conservation, were determined using internally developed models that consider various factors, including historical, trend and regression analysis. The models also consider economic and market variables.

3. Forecasted deliveries assumed 6,031 normal heating degree-days. This represents the average of actual weather at O'Hare International Airport for the 12-year period from 2001 through 2012 adjusted for any leap years during this period.

4. Based on the above volume assumptions, forecasted deliveries to customers are 34.0 Bcf, including 20.5 Bcf delivered to sales customers and 13.5 Bcf delivered to transportation customers.

5. Revenues not associated with delivery volumes were determined primarily from historical factors or the number of customers. Revenues for large customers with special contracts were based on a combination of historical and projected data.

6. Late payment charges were forecasted to be $0.6 million. This estimate reflects the monthly average actual late payment charges for the previous two years.

7. Revenue attributable to the recovery of environmental clean-up costs (Rider 11 revenue) is forecast at $11.1 million. There is a corresponding charge to expense, and thus these revenues have no direct impact on forecasted income.

8. Revenue attributable to Rider EOA is forecast at $4.3 million. There is a corresponding charge to expense, and thus these revenues have no direct impact on forecasted income.

9. Recoveries attributable to NSG's decoupling mechanism (Rider VBA) are forecast at $0.8 million based on lower 2015 forecasted distribution charge revenue derived from Service Classification No. 1 and Service Classification No 2 compared to the Rider VBA Rate Case Revenue derived from the rates approved per the Company's revenue requirement in Docket Nos. 12-0511/12-0512 (Cons.) Order on Rehearing.

10. The forecast assumes no significant changes to the customer base.

II. <u>Cost of Gas</u>

1. The cost of gas purchased for sales to customers is passed on directly to customers without mark-up. Therefore, while a change in the forecast of gas costs may have a significant effect on revenue and the cost of gas, it would

not have a significant impact on the Company's forecast of income. Indirectly, changes in the cost of gas impact customer delivered volumes and the forecast of other costs.

2. The forecasted cost of gas purchased for sales to customers includes natural gas commodity costs and non-commodity costs, along with changes in inventory and adjustments for prior and forecasted over/under collections of gas costs from customers. At the end of 2015, the forecasted under collection from customers is $0.8 million. This is based on forecasted monthly differences between actual gas costs and billed gas costs due in part to timing differences amortized over a 12 month period.

3. Non-commodity costs, primarily pipeline transportation and storage demand charges, are generally based on contractual volumes and rates in place at July 31, 2013. No material changes are expected in these contracts for the forecast period.

4. Forecasted commodity costs were based on the product of forecasted purchase volumes and forecasted gas purchase costs.

5. Forecasted purchase volumes include lost and unaccounted-for gas. The Company forecasted an unaccounted-for loss rate of 1.54% of forecasted retail deliveries. This rate is based on the most recent historical twelve month average of the lost and unaccounted for factor.

6. Forecasted gas purchase costs are determined by applying the forward NYMEX gas price as of July 31, 2013, adjusted for applicable basis differentials and existing hedge positions in place. The unweighted average of the forward NYMEX gas prices is $4.09 per MMBtu.

III. Operations and Maintenance Costs

1. Labor

   a. The number of employees is forecasted to be 178 in calendar years 2014 and 2015. Actual headcount at July 31, 2013 was 169.

   b. Union employee wages are forecasted to increase 3.0% in May, 2014 and May, 2015. An increase of 0.65% was also included for progressions in both years.

   c. Non-union wages are forecasted to increase 3.6% in March of calendar 2014 and 2015.

2. Bad Debt

   The provision for bad debt recorded in Account 904 – Uncollectible Accounts was forecast at 0.7% of revenue. This rate is consistent with the average actual provision rate the last six years. In 2013, NSG switched to the net-write-off method which was approved in the final Order in Docket Nos. 11-0280/11-0281 (Cons.). Under this method, the difference between rate case approved net write-offs plus the Rider UEA-GC revenue for the reporting period and actual net write-offs for the reporting period will be deferred as a regulatory asset and/or liability. Amounts deferred will be recovered from or refunded to customers through the uncollectible expense adjustment mechanism (Rider UEA).

3. Pension and Postretirement Expense

   Pension and postretirement expense was developed with the assistance of the Company's actuaries. The census data used was as of January 1, 2013. The discount rate assumption for pension expense was forecast at 4.80%, and the discount rate assumption for postretirement expense was forecast at 4.60%, which are the discount rates at July 31, 2013. The expected return on plan assets is 8% based on current mix of plan assets. The forecast used the estimated market-related value of plan assets at December 31, 2013, and assumes NSG will contribute $5.1 million to its pension plan and $1.0 million to its other postretirement benefit plan in 2014 and $3.8 million to its pension plan and $1.0 million to its other postretirement plan during 2015.

4. Environmental Costs

   Costs related to the investigation and removal of manufactured gas residues are initially recorded in a regulatory asset account. Expenditures related to the remediation of environmental obligations reflected in the forecasted statements are $14.6 million and $0.7 million for 2014 and 2015. NSG has a recovery mechanism in place (Rider 11) that provides for dollar for dollar recovery of the expenditures. Revenue attributable to the recovery of environmental clean-up costs (Rider 11 revenue) is forecast at $11.1 million for 2015. There is a corresponding charge to expense, and therefore, no direct impact to forecasted income. Liabilities were developed based on engineering costs estimates and probable outcomes, and were based on a review and judgment by the Company's management and outside consultants. The forecast assumes no changes in the liability estimate in 2014 or 2015 except for the reduction in the liability driven by expenditures for remediation.

5. Energy Efficiency and On-Bill Financing Costs

   Costs related to the Energy Efficiency and On-Bill Financing programs are expensed as incurred. The difference between the budgeted monthly expenditure billed to customers and the actual expenses is recorded as a regulatory asset or liability with a corresponding adjustment to expense. The amount forecasted to be billed to customers, with an offsetting expense in operating and maintenance expenses is $4.3 million in calendar 2015 and therefore will not directly impact forecasted income.

6. Intercompany Billing Charges

   Various services are performed by affiliates of NSG and those costs are billed to NSG on a monthly basis. These costs are billed to and paid by the Company in accordance with the Master Regulated Affiliated Interest Agreement approved by the ICC in Docket No. 07-0361 and, beginning in Janaury 2014, the Affiliated Interest Agreement approved by the ICC in Docket No. 10-0408. The ICC must approve changes or amendments to the Master Regulated Affiliated Interest Agreement.

7. Other Costs

   The Company forecasted operating and maintenance costs through a detailed bottoms-up budgeting process. Unless specifically determined otherwise, this process assumes, as a default, a 2.1% and 2.4% annual rate of inflation for 2014 and 2015 respectively. The cost of natural gas purchased for the Company's internal use was forecasted in a similar manner as natural gas purchased for sales to customers.

IV. Depreciation

The provision for depreciation, expressed as an annual percentage of the original cost of depreciable property, is 2.5% for calendar year 2015.

Depreciation expense in calendar year 2015 is based on the average estimated life of depreciable property. Estimated lives were based on the depreciation study prepared by Gannet Fleming and are submitted as part of the 2015 test year rate case.

V. Income Taxes

1. Income taxes were forecast by applying the current federal and state statutory income tax rates to forecasted pre-tax income, after adjusting for forecasted permanent items. For 2015, federal and state income tax rates are 35% and 7.75%. See 2 below for deferred tax component.

2. The deferred tax provision for originating differences is based on current federal and state statutory rates from 1 above. The deferred tax provision for reversing temporary differences is based on the average rate assumption method. However, consistent with the Commission order in Docket Nos. 12-0511/12-0512 (Cons.), Originating plant related differences for all periods between 2011 and 2015 are recorded by flowing through the excess deferred taxes generated by the Illinois scheduled income tax rates

3. The consolidated group of companies generated a net operating loss ("NOL") for 2012 and 2013 is assumed to be in an NOL position as well. For 2014 and 2015,

the consolidated group is assumed to be in an income position sufficient to absorb consolidated loss carry forwards and return to a tax-paying position. Therefore, a deferred tax asset will be computed on a standalone basis for 2012 and 2013. In 2014 a significant portion of this amount will be reversed reflecting utilization of the consolidated loss carry-forward during that year. The test year opening balance in rate base will therefore include the balance of the remaining amount of the deferred tax asset. In 2015, it is assumed this remainder of the consolidated carry-forward will be utilized by the consolidated group, and therefore the deferred tax asset at the end of 2015 will be zero. All of the assumptions made here will be monitored / updated at each step in this 2015 test year rate case proceeding. Depending on the developments, the updates may affect the proposed rate base.

VI. Short-term and Long-Term Debt

The forecast assumes all short-term borrowings will be intercompany from Integrys Energy Group, Inc. Short-term borrowings are used to fund operating and investing activities when operating cash flows are insufficient and are a bridge to the issuance of long-term funding in the form of equity and long-term debt issuances.

The forecast includes the maturity of $6.5 million Series O on November 1, 2013 at an annual interest rate of 7.00%. No other changes to long-term debt are forecasted.

VII. Interest Income and Expense

1. Interest expense includes a) interest on long-term debt, b) amortization of debt issuance costs and losses on reacquired debt, c) interest and fees associated with short-term borrowings and lines of credit, and d) interest expense related to customer deposits, budget plan customers, employee deferred compensation balances, and over-collected gas costs.

2. For fixed rate long-term debt, interest expense is forecast by applying the stated interest rate to the principal amount of each series of currently outstanding first-mortgage bonds. Debt amortizations are initially calculated over the life of the debt issue. If debt is reacquired and not refinanced, debt expense amortization continues over the original life. For refinanced debt issues any unamortized amounts are subsequently amortized over the life of the new debt issue.

3. For variable rate short-term debt, interest expense was forecasted with rates derived based on the sum of the 1 month non-financial commercial paper rates for 2015 and an average spread between A2/P2 and AA commercial paper. Short-term debt expense also includes bank fees associated with lines of credit.

VIII. Dividends / Common Equity

No dividends are forecasted for 2015. Dividends are forecasted in May 2014 at $19.0 million.

IX. Capital Expenditures

Capital expenditures were forecasted as follows for calendar 2014 and 2015 ($ in millions):

	2014	2015
Distribution system	$19.5	$12.6
Transmission	7.9	11.7
Other	2.7	3.8
Total	$30.1	$28.1

North Shore Gas Company

Statement on Assumptions Used in the Forecast

a) The forecast for the test year contains the same assumptions and methodologies used in forecasts that are prepared for management or other entities such as the Securities and Exchange Commission, security rating companies and agencies, underwriters, and investors, except as described in c) below.

b) There are no differences in assumptions or methodologies used in the forecast of the test year and in forecasts prepared for management or other entities, except as described in c) below.

c) The test year forecast approved as of December 2013 assumes: (a) current tariffed rates remain in effect through December 31, 2015 and (b) forecasted natural gas commodity prices reflect the average of the New York Mercantile Exchange (“NYMEX”) futures prices for 2015 for the thirty day period ended July 31, 2013 and (c) sales volumes were updated to reflect six months actual through June 30, 2013.

North Shore Gas Company

Statement on Accounting Treatment

a) The accounting treatment applied to anticipated events and transactions in the forecast is the same as the accounting treatment to be applied in recording the events once they have occurred.

b) There are no differences between the accounting treatment applied to anticipated events and transactions in the forecast forming the basis of the test year and the accounting treatment to be applied in recording the event once it has occurred.

North Shore Gas Company

Summary of Significant Accounting Policies and Assumptions

Used in the Forecast For the Year Ending December 31, 2015

PRESENTATION BASIS

The financial forecast has been prepared by North Shore Gas Company ("the Company" or "NSG") and presented in accordance with the guidelines established in the November 1, 2012 AICPA Prospective Financial Information Guide. This financial forecast presents, to the best of management's knowledge and belief, the Company's expected financial position, results of operations, retained earnings and cash flows for the forecast period. Accordingly, the forecast reflects management's judgment as of July 31, 2013, the date of this forecast, of the expected conditions and management's expected course of action. Final approval of the financial forecast was in December 2013. The assumptions disclosed herein are those that management believes are significant to the forecast. There will usually be differences between the forecasted and actual results, because events and circumstances frequently do not occur as expected, and those differences may be material.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The accounting policies used in preparing the forecast are below and are the same as in the Company's audited financial statements.

I. Nature of Operations

NSG is a regulated natural gas utility company that purchases, stores, distributes, sells, and transports natural gas to customers in the northern suburbs of Chicago. NSG is subject to the jurisdiction of, and regulation by, the Illinois Commerce Commission ("ICC"), which has general supervisory and regulatory powers over public utilities in Illinois, and the Federal Energy Regulatory Commission ("FERC"), which regulates the interstate services NSG provides. The term "utility" refers to NSG's regulated activities.

As used in these notes, the term "financial statements" includes the statement of income, balance sheet, retained earnings and statement of cash flows, unless otherwise noted.

II. Use of Estimates

NSG prepares its financial statements in conformity with accounting principles generally accepted in the United States of America ("GAAP"). NSG makes estimates and assumptions that affect assets, liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements. Actual results may differ from these estimates.

III. Cash and Cash Equivalents

Short-term investments with an original maturity of three months or less are reported as cash equivalents.

IV. Revenues and Customer Receivables

Revenues related to the sale of natural gas are recognized when service is provided or natural gas is delivered to customers. NSG also accrues estimated amounts of revenues for services provided or natural gas delivered but not yet billed to customers. Estimated unbilled revenues are calculated using a variety of judgments and assumptions related to customer class, contracted rates, weather, and customer use. NSG presents revenues net of pass-through taxes on the income statements.

NSG has various revenue and cost recovery adjustment mechanisms in place that currently provide for the recovery of prudently incurred costs and baseline revenue amounts. A summary of the significant adjustment mechanisms which are included in rates follows:

- A one-for-one recovery mechanism for natural gas commodity and capacity costs.
- Riders for cost recovery for both environmental cleanup and energy efficiency and on-bill financing program costs.
- A rider for cost recovery or refund of uncollectible accounts expense based on the difference between actual net write-offs and the amount allowed in rates (as defined in the latest rate order) as well as amounts recovered under Rider UEA-GC (Uncollectible Expense Adjustment – Gas Costs).
- A Volume Balancing Adjustment (Rider VBA) decoupling mechanism, which allows NSG to bill adjustments going forward to recover or refund the differences between the actual and authorized distribution margin for its residential and general service rate classes. In the first quarter of 2013, the Illinois Appellate Court affirmed the ICC's authority to approve a permanent decoupling mechanism and therefore, NSG assumes in this forecast that it will continue to file these adjustments with the ICC for the recovery/refund of amounts recorded related to decoupling. In June 2013, the Illinois Attorney General and Citizens Utility Board petitioned the Illinois Supreme Court to appeal the Court's decision. The Illinois Supreme Court granted the request in September 2013. The Illinois Supreme Court has no deadline by which it must act.

V. Inventories

Inventories consist of materials and supplies, natural gas in storage, and liquid propane. Materials and supplies and liquid propane inventory are priced at average cost. NSG prices natural gas storage injections at the calendar year average of the costs of natural gas supply purchased. Withdrawals from storage are priced on the LIFO cost method.

VI. Risk Management Activities

As part of NSG's regular operations, NSG enters into contracts, including options, forwards, and swaps, to manage changes in commodity prices.

All derivatives are recognized on the balance sheets at their fair value unless they are designated as and qualify for the normal purchases and sales exception. NSG continually assesses its contracts designated as normal and will discontinue the treatment of these contracts as normal if the required criteria are no longer met. NSG's tariffs allow for full recovery from its customers of prudently incurred natural gas supply costs, including gains or losses on these derivative instruments. These derivatives are marked to fair value; the resulting risk management assets are offset with regulatory liabilities or decreases to regulatory assets, and risk management liabilities are offset with regulatory assets or decreases to regulatory liabilities. Management believes any gains or losses resulting from the eventual settlement of these derivative instruments will be refunded to or collected from customers in rates.

NSG has risk management contracts with various counterparties. NSG monitors credit exposure levels and the financial condition of its counterparties on a continuous basis to minimize credit risk.

VII. Property, Plant, and Equipment

Utility plant is stated at cost, including any associated allowance for funds used during construction and asset retirement costs. The costs of renewals and betterments of units of property (as distinguished from minor items of property) are capitalized as additions to the utility plant accounts. Maintenance, repair, replacement, and renewal costs associated with items not qualifying as units of property are considered operating expenses. NSG records a regulatory liability for cost of removal accruals, which are included in rates. Actual removal costs are charged against the regulatory liability as incurred. Except for land, no gains or losses are recognized in connection with ordinary retirements of utility property units. NSG charges the cost of units of property retired, sold, or otherwise disposed of, less salvage value, to accumulated depreciation.

NSG records straight-line depreciation expense over the estimated useful life of utility property, using depreciation rates as approved by the ICC. The provision for depreciation, expressed as an annual percentage of the original cost of depreciable property, is 2.5% for the forecasted year ending December 31, 2015.

VIII. Regulatory Assets and Liabilities

Regulatory assets represent probable future revenue associated with certain costs or liabilities that have been deferred and are expected to be recovered from customers through the ratemaking process. Regulatory liabilities represent amounts that are expected to be refunded to customers in future rates or amounts collected in rates for future costs. If at any reporting date a previously recorded regulatory asset is no longer probable of recovery, the regulatory asset is reduced to the amount considered probable of recovery with the reduction charged to expense in the year the determination is made.

IX. Retirement of Debt

Any call premiums or unamortized expenses associated with refinancing utility debt obligations are amortized consistent with regulatory treatment of those items. Any gains or losses resulting from the retirement of utility debt that is not refinanced are amortized over the remaining life of the original debt.

X. Asset Retirement Obligations

NSG recognizes at fair value legal obligations associated with the retirement of tangible long-lived assets that result from the acquisition, construction or development, and/or normal operation of the assets. A liability is recorded for these obligations as long as the fair value can be reasonably estimated, even if the timing or method of settling the obligation is unknown. The asset retirement obligations are accreted using a credit-adjusted risk-free interest rate commensurate with the expected settlement dates of the asset retirement obligations; this rate is determined at the date the obligation is incurred. The associated retirement costs are capitalized as part of the related long-lived assets and are depreciated over the useful lives of the assets. Subsequent changes resulting from revisions to the timing or the amount of the original estimate of undiscounted cash flows are recognized as an increase or a decrease in the carrying amount of the liability and the associated retirement cost.

XI. Income Taxes

NSG is included in the consolidated United States income tax return filed by Integrys Energy Group. NSG is party to a federal and state tax allocation arrangement with Integrys Energy Group and its subsidiaries under which each entity determines its provision for income taxes on a stand-alone basis. NSG settles the intercompany income taxes payable at the time that payments are made to the applicable taxing authority.

Deferred income taxes have been recorded to recognize the expected future tax consequences of events that have been included in the financial statements by using currently enacted tax rates for the differences between the income tax basis of assets and liabilities and the basis reported in the financial statements. NSG records valuation allowances for deferred income tax assets unless it is more likely than not that the benefit will be realized in the future. NSG defers certain adjustments made to income taxes that will impact future rates and records regulatory assets or liabilities related to these adjustments.

NSG uses the deferral method of accounting for investment tax credits (ITCs). Under this method, NSG records the ITCs as deferred credits and amortizes such credits as a reduction to the provision for income taxes over the life of the asset that generated the ITCs. ITCs that do not reduce income taxes payable for the current year are eligible for carryover and recognized as a deferred income tax asset.

NSG reports interest and penalties accrued related to income taxes as a component of provision for income taxes in the income statements.

XII. Employee Benefits

The costs of pension and other postretirement benefits are expensed over the periods during which employees render service. Effective with new rates implemented in 2010, NSG began reflecting pension and other postretirement benefit costs in rates using Integrys Energy Group's basis in the related plan assets and obligations and method of determining these costs, which Integrys Energy Group established at the time of the February 2007 Peoples Energy, LLC ("PELLC") merger. In addition, the cumulative difference between NSG's accounting basis and the accounting basis of Integrys Energy Group in NSG's pension and postretirement benefit obligations is being amortized as a component of NSG's rates over the average remaining service lives of the participating employees. In computing the expected return on pension plan assets, a market-related value of plan assets is used that recognizes differences between actual investment returns and the expected return on plan assets over the subsequent five years. NSG's regulators allow recovery in rates for the net periodic benefit cost calculated under GAAP.

NSG recognizes the funded status of defined benefit postretirement plans on the balance sheet, and recognizes changes in the plans' funded status in the year in which the changes occur. NSG records changes in the funded status to regulatory asset or liability accounts, pursuant to the Regulated Operations Topic of the FASB ASC.

NSG accounts for its participation in benefit plans sponsored by Integrys Business Support, LLC ("IBS") and PELLC as multiple employer plans. Under affiliate agreements, NSG is responsible for its share of plan costs and obligations and is entitled to its share of plan assets; accordingly, NSG accounts for its pro rata share of the IBS and PELLC plans as its own plans.

XIII. Fair Value

A fair value measurement is required to reflect the assumptions market participants would use in pricing an asset or liability based on the best available information. These assumptions include the risks inherent in a particular valuation technique (such as a pricing model) and the risks inherent in the inputs to the model.

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). NSG uses a mid-market pricing convention (the mid-point price between bid and ask prices) as a practical measure for valuing the majority of its derivative assets and liabilities.

Fair value accounting rules provide a hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). The three levels of the fair value hierarchy are defined as follows:

Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 – Pricing inputs are observable, either directly or indirectly, but are not quoted prices included within Level 1. Level 2 includes those financial instruments that are valued using external inputs within models or other valuation methodologies.

Level 3 – Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value.

Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement.

NSG determines fair value using a market-based approach that uses observable market inputs where available, and internally developed inputs where observable market data is not readily available. For the unobservable inputs, consideration is given to the assumptions that market participants would use in valuing the asset or liability. These factors include not only the credit standing of the counterparties involved, but also the impact of NSG's nonperformance risk on its liabilities.

When possible, NSG bases the valuations of its risk management assets and liabilities on quoted prices for identical assets in active markets. These valuations are classified in Level 1. The valuations of certain contracts include inputs related to market price risk (commodity or interest rate), price volatility (for option contracts), price correlation (for cross commodity contracts), probability of default, and time value. These inputs are available through multiple sources, including brokers and over-the-counter and online exchanges. Transactions valued using these inputs are classified in Level 2. Transactions classified in Level 3 include significant inputs that are generally less observable from objective sources and/or are used with internally developed methodologies to calculate management's best estimate of fair value. At this time, NSG does not have any Level 3 fair value measurements.

SUMMARY OF SIGNIFICANT ASSUMPTIONS

I. Operating Revenues

1. Forecasted revenues were primarily determined by applying the Company's current rates and rate structure to forecasted deliveries of gas to customers, plus the forecasted cost of gas delivered, environmental recovery charges, Energy Efficiency and On-Bill Financing Adjustment ("Rider EOA") charges, the Rider VBA adjustments and other miscellaneous charges and adjustments.

2. Forecasted deliveries, including changes due to customer growth and conservation, were determined using internally developed models that consider various factors, including historical, trend and regression analysis. The models also consider economic and market variables.

3. Forecasted deliveries assumed 6,031 normal heating degree-days. This represents the average of actual weather at O'Hare International Airport for the 12-year period from 2001 through 2012 adjusted for any leap years during this period.

4. Based on the above volume assumptions, forecasted deliveries to customers are 34.0 Bcf, including 20.5 Bcf delivered to sales customers and 13.5 Bcf delivered to transportation customers.

5. Revenues not associated with delivery volumes were determined primarily from historical factors or the number of customers. Revenues for large customers with special contracts were based on a combination of historical and projected data.

6. Late payment charges were forecasted to be $0.6 million. This estimate reflects the monthly average actual late payment charges for the previous two years.

7. Revenue attributable to the recovery of environmental clean-up costs (Rider 11 revenue) is forecast at $11.1 million. There is a corresponding charge to expense, and thus these revenues have no direct impact on forecasted income.

8. Revenue attributable to Rider EOA is forecast at $4.3 million. There is a corresponding charge to expense, and thus these revenues have no direct impact on forecasted income.

9. Recoveries attributable to NSG's decoupling mechanism (Rider VBA) are forecast at $0.8 million based on lower 2015 forecasted distribution charge revenue derived from Service Classification No. 1 and Service Classification No 2 compared to the Rider VBA Rate Case Revenue derived from the rates approved per the Company's revenue requirement in Docket Nos. 12-0511/12-0512 (Cons.) Order on Rehearing.

10. The forecast assumes no significant changes to the customer base.

II. <u>Cost of Gas</u>

1. The cost of gas purchased for sales to customers is passed on directly to customers without mark-up. Therefore, while a change in the forecast of gas costs may have a significant effect on revenue and the cost of gas, it would

not have a significant impact on the Company's forecast of income. Indirectly, changes in the cost of gas impact customer delivered volumes and the forecast of other costs.

2. The forecasted cost of gas purchased for sales to customers includes natural gas commodity costs and non-commodity costs, along with changes in inventory and adjustments for prior and forecasted over/under collections of gas costs from customers. At the end of 2015, the forecasted under collection from customers is $0.8 million. This is based on forecasted monthly differences between actual gas costs and billed gas costs due in part to timing differences amortized over a 12 month period.

3. Non-commodity costs, primarily pipeline transportation and storage demand charges, are generally based on contractual volumes and rates in place at July 31, 2013. No material changes are expected in these contracts for the forecast period.

4. Forecasted commodity costs were based on the product of forecasted purchase volumes and forecasted gas purchase costs.

5. Forecasted purchase volumes include lost and unaccounted-for gas. The Company forecasted an unaccounted-for loss rate of 1.54% of forecasted retail deliveries. This rate is based on the most recent historical twelve month average of the lost and unaccounted for factor.

6. Forecasted gas purchase costs are determined by applying the forward NYMEX gas price as of July 31, 2013, adjusted for applicable basis differentials and existing hedge positions in place. The unweighted average of the forward NYMEX gas prices is $4.09 per MMBtu.

III. Operations and Maintenance Costs

1. Labor

   a. The number of employees is forecasted to be 178 in calendar years 2014 and 2015. Actual headcount at July 31, 2013 was 169.

   b. Union employee wages are forecasted to increase 3.0% in May, 2014 and May, 2015. An increase of 0.65% was also included for progressions in both years.

   c. Non-union wages are forecasted to increase 3.6% in March of calendar 2014 and 2015.

2. Bad Debt

   The provision for bad debt recorded in Account 904 – Uncollectible Accounts was forecast at 0.7% of revenue. This rate is consistent with the average actual provision rate the last six years. In 2013, NSG switched to the net-write-off method which was approved in the final Order in Docket Nos. 11-0280/11-0281 (Cons.). Under this method, the difference between rate case approved net write-offs plus the Rider UEA-GC revenue for the reporting period and actual net write-offs for the reporting period will be deferred as a regulatory asset and/or liability. Amounts deferred will be recovered from or refunded to customers through the uncollectible expense adjustment mechanism (Rider UEA).

3. Pension and Postretirement Expense

Pension and postretirement expense was developed with the assistance of the Company's actuaries. The census data used was as of January 1, 2013. The discount rate assumption for pension expense was forecast at 4.80%, and the discount rate assumption for postretirement expense was forecast at 4.60%, which are the discount rates at July 31, 2013. The expected return on plan assets is 8% based on current mix of plan assets. The forecast used the estimated market-related value of plan assets at December 31, 2013, and assumes NSG will contribute $5.1 million to its pension plan and $1.0 million to its other postretirement benefit plan in 2014 and $3.8 million to its pension plan and $1.0 million to its other postretirement plan during 2015.

4. Environmental Costs

Costs related to the investigation and removal of manufactured gas residues are initially recorded in a regulatory asset account. Expenditures related to the remediation of environmental obligations reflected in the forecasted statements are $14.6 million and $0.7 million for 2014 and 2015. NSG has a recovery mechanism in place (Rider 11) that provides for dollar for dollar recovery of the expenditures. Revenue attributable to the recovery of environmental clean-up costs (Rider 11 revenue) is forecast at $11.1 million for 2015. There is a corresponding charge to expense, and therefore, no direct impact to forecasted income. Liabilities were developed based on engineering costs estimates and probable outcomes, and were based on a review and judgment by the Company's management and outside consultants. The forecast assumes no changes in the liability estimate in 2014 or 2015 except for the reduction in the liability driven by expenditures for remediation.

5. Energy Efficiency and On-Bill Financing Costs

Costs related to the Energy Efficiency and On-Bill Financing programs are expensed as incurred. The difference between the budgeted monthly expenditure billed to customers and the actual expenses is recorded as a regulatory asset or liability with a corresponding adjustment to expense. The amount forecasted to be billed to customers, with an offsetting expense in operating and maintenance expenses is $4.3 million in calendar 2015 and therefore will not directly impact forecasted income.

6. Intercompany Billing Charges

   Various services are performed by affiliates of NSG and those costs are billed to NSG on a monthly basis. These costs are billed to and paid by the Company in accordance with the Master Regulated Affiliated Interest Agreement approved by the ICC in Docket No. 07-0361 and, beginning in Janaury 2014, the Affiliated Interest Agreement approved by the ICC in Docket No. 10-0408. The ICC must approve changes or amendments to the Master Regulated Affiliated Interest Agreement.

7. Other Costs

   The Company forecasted operating and maintenance costs through a detailed bottoms-up budgeting process. Unless specifically determined otherwise, this process assumes, as a default, a 2.1% and 2.4% annual rate of inflation for 2014 and 2015 respectively. The cost of natural gas purchased for the Company's internal use was forecasted in a similar manner as natural gas purchased for sales to customers.

IV. Depreciation

The provision for depreciation, expressed as an annual percentage of the original cost of depreciable property, is 2.5% for calendar year 2015.

Depreciation expense in calendar year 2015 is based on the average estimated life of depreciable property. Estimated lives were based on the depreciation study prepared by Gannet Fleming and are submitted as part of the 2015 test year rate case.

V. Income Taxes

1. Income taxes were forecast by applying the current federal and state statutory income tax rates to forecasted pre-tax income, after adjusting for forecasted permanent items. For 2015, federal and state income tax rates are 35% and 7.75%. See 2 below for deferred tax component.

2. The deferred tax provision for originating differences is based on current federal and state statutory rates from 1 above. The deferred tax provision for reversing temporary differences is based on the average rate assumption method. However, consistent with the Commission order in Docket Nos. 12-0511/12-0512 (Cons.), Originating plant related differences for all periods between 2011 and 2015 are recorded by flowing through the excess deferred taxes generated by the Illinois scheduled income tax rates

3. The consolidated group of companies generated a net operating loss ("NOL") for 2012 and 2013 is assumed to be in an NOL position as well. For 2014 and 2015,

the consolidated group is assumed to be in an income position sufficient to absorb consolidated loss carry forwards and return to a tax-paying position. Therefore, a deferred tax asset will be computed on a standalone basis for 2012 and 2013. In 2014 a significant portion of this amount will be reversed reflecting utilization of the consolidated loss carry-forward during that year. The test year opening balance in rate base will therefore include the balance of the remaining amount of the deferred tax asset. In 2015, it is assumed this remainder of the consolidated carry-forward will be utilized by the consolidated group, and therefore the deferred tax asset at the end of 2015 will be zero. All of the assumptions made here will be monitored / updated at each step in this 2015 test year rate case proceeding. Depending on the developments, the updates may affect the proposed rate base.

VI. Short-term and Long-Term Debt

The forecast assumes all short-term borrowings will be intercompany from Integrys Energy Group, Inc. Short-term borrowings are used to fund operating and investing activities when operating cash flows are insufficient and are a bridge to the issuance of long-term funding in the form of equity and long-term debt issuances.

The forecast includes the maturity of $6.5 million Series O on November 1, 2013 at an annual interest rate of 7.00%. No other changes to long-term debt are forecasted.

VII. Interest Income and Expense

1. Interest expense includes a) interest on long-term debt, b) amortization of debt issuance costs and losses on reacquired debt, c) interest and fees associated with short-term borrowings and lines of credit, and d) interest expense related to customer deposits, budget plan customers, employee deferred compensation balances, and over-collected gas costs.

2. For fixed rate long-term debt, interest expense is forecast by applying the stated interest rate to the principal amount of each series of currently outstanding first-mortgage bonds. Debt amortizations are initially calculated over the life of the debt issue. If debt is reacquired and not refinanced, debt expense amortization continues over the original life. For refinanced debt issues any unamortized amounts are subsequently amortized over the life of the new debt issue.

3. For variable rate short-term debt, interest expense was forecasted with rates derived based on the sum of the 1 month non-financial commercial paper rates for 2015 and an average spread between A2/P2 and AA commercial paper. Short-term debt expense also includes bank fees associated with lines of credit.

VIII. Dividends / Common Equity

No dividends are forecasted for 2015. Dividends are forecasted in May 2014 at $19.0 million.

IX. Capital Expenditures

Capital expenditures were forecasted as follows for calendar 2014 and 2015 ($ in millions):

	2014	2015
Distribution system	$19.5	$12.6
Transmission	7.9	11.7
Other	2.7	3.8
Total	$30.1	$28.1

North Shore Gas Company

Inflation

Line No.	Description	Base Dollars	Inflation Factor	Inflation Amount	Line No.
	[A]	[B]	[C]	[D] = [B] x [C]	
1	**Invoices**				1
2	Transportation costs				2
3	B02 Fleet	388,000	2.40%	9,000	3
4	**Contract/Outsource/Consulting Services**				4
5	Administrative and General				5
6	A16 Regulatory Affairs	35,000	2.40%	1,000	6
7	Customer Accounts				7
8	AF5 M2C Collections CHIC	45,000	2.40%	1,000	8
9	**Other Taxes**				9
10	Regulatory Assets				10
11	B61 MGP Site - North Plant/Tar Pit	42,000	2.40%	1,000	11
12	Taxes Other than Income Taxes				12
13	B09 Tax Programs	287,000	2.40%	7,000	13
14	**Fuel On-Site Tanks**				14
15	Transportation Costs				15
16	B02 Fleet	590,000	2.40%	14,000	16

North Shore Gas Company

Proration of Accumulated Deferred Income Taxes

Test Year Ending December 31, 2015

Line No.	Description	Days(1)	Ratio	Liberalized Depreciation Statutory Rate Per Books	Liberalized Depreciation Statutory Rate Prorated	Line No.
	[A]	[B]	[C]	[D]	[E]	
1	Balance 12/31/2014			$ (58,752,000)	$ (58,752,000)	1
2	January	335	100.0%	(25,000)	(25,000)	2
3	February	307	91.6%	(25,000)	(23,000)	3
4	March	276	82.4%	(25,000)	(21,000)	4
5	April	246	73.4%	(24,000)	(18,000)	5
6	May	215	64.2%	(25,000)	(16,000)	6
7	June	185	55.2%	(25,000)	(14,000)	7
8	July	154	46.0%	(25,000)	(12,000)	8
9	August	123	36.7%	(25,000)	(9,000)	9
10	September	93	27.8%	(25,000)	(7,000)	10
11	October	62	18.5%	(24,000)	(4,000)	11
12	November	32	9.6%	(25,000)	(2,000)	12
13	December	1	0.3%	(25,000)	0	13
14	Balance 12/31/2015			$ (59,050,000)	$ (58,903,000)	14
15	Impact of Proration (Col E, line 14 - Col D, line 14) - amount shown on Schedule B-9				$ 147,000	15

Notes: (1)Total days in period: 335

Assumes rates become effective February 1, 2015

North Shore Gas Company

Actual Gross Additions and Retirements
Compared to Original Budget

Line No.	Plant Function	Historical Year Ended December 31, 2010 — Gross Additions — Actual	Gross Additions — Budget	Gross Additions — Difference	Retirements — Actual	Retirements — Budget	Retirements — Difference	Line No.
	[A]	[B]	[C]	[D]	[E]	[F]	[G]	
1	Distribution	$ 9,531,000	$ 17,822,000	$ (8,291,000)	$ (1,053,000)	$ (2,152,000)	$ 1,099,000	1
2	Underground Storage	-	-	-	-	-	-	2
3	Transmission - Not Leased	186,000	-	186,000	-	-	-	3
4	General	543,000	1,197,000	(654,000)	(3,385,000)	(68,000)	(3,317,000)	4
5	Intangible	-	-	-	-	-	-	5
6	Production	(1,000)	-	(1,000)	-	-	-	6
7	Total Account 101	10,259,000	19,019,000	(8,760,000)	(4,438,000)	(2,220,000)	(2,218,000)	7
8	Recoverable Natural Gas (Account 117)	-	-	-	-	-	-	8
9	Total Plant In Service	$ 10,259,000	$ 19,019,000	$ (8,760,000)	$ (4,438,000)	$ (2,220,000)	$ (2,218,000)	9

North Shore Gas Company

Actual Gross Additions and Retirements
Compared to Original Budget

Line No.	Plant Function	Gross Additions Actual	Gross Additions Budget	Gross Additions Difference	Retirements Actual	Retirements Budget	Retirements Difference	Line No.
		Historical Year Ended December 31, 2011						
	[A]	[B]	[C]	[D]	[E]	[F]	[G]	
1	Distribution	$ 9,488,000	$ 10,262,000	$ (774,000)	$ (2,227,000)	($1,912,000)	$ (315,000)	1
2	Underground Storage	-	-	-	-	-	-	2
3	Transmission - Not Leased	1,029,000	89,000	940,000	-	-	-	3
4	General	1,640,000	2,639,000	(999,000)	(1,280,000)	(51,000)	(1,229,000)	4
5	Intangible	-	-	-	-	-	-	5
6	Production	281,000	50,000	231,000	(1,000)	-	(1,000)	6
7	Total Account 101	12,438,000	13,040,000	(602,000)	(3,508,000)	(1,963,000)	(1,545,000)	7
8	Recoverable Natural Gas (Account 117)	-	-	-	-	-	-	8
9	Total Plant In Service	$ 12,438,000	$ 13,040,000	$ (602,000)	$ (3,508,000)	$ (1,963,000)	$ (1,545,000)	9

North Shore Gas Company

Actual Gross Additions and Retirements
Compared to Original Budget

Line No.	Plant Function	Historical Year Ended December 31, 2012 Gross Additions Actual	Budget	Difference	Retirements Actual	Budget	Difference	Line No.
	[A]	[B]	[C]	[D]	[E]	[F]	[G]	
1	Distribution	$ 17,531,000	$ 31,603,000	$ (14,072,000)	$ (2,129,000)	$ (1,718,000)	$ (411,000)	1
2	Underground Storage	-	-	-	-	-	-	2
3	Transmission - Not Leased	937,000	91,000	846,000	-	-	-	3
4	General	2,158,000	3,691,000	(1,533,000)	(753,000)	(870,000)	117,000	4
5	Intangible	-	-	-	-	-	-	5
6	Production	233,000	115,000	118,000	(38,000)	-	(38,000)	6
7	Total Account 101	20,859,000	35,500,000	(14,641,000)	(2,920,000)	(2,588,000)	(332,000)	7
8	Recoverable Natural Gas (Account 117)	-	-	-	-	-	-	8
9	Total Plant In Service	$ 20,859,000	$ 35,500,000	$ (14,641,000)	$ (2,920,000)	$ (2,588,000)	$ (332,000)	9

North Shore Gas Company

Comparison of Budgeted Non-Payroll Expense to Actual

Line No.	Account Number and Description		Historical Year Ended December 31, 2010 Actual	Budget	Variance	% Variance	Line No.
	[A]		[B]	[C]	[D]	[E]	
1	**Production**						1
2	Operation						2
3	710	Operation Supervision and Engineering	$ 11,000	$ -	$ 11,000	-	3
4	717	Liquefied Petroleum Gas Expenses	7,000	14,000	(7,000)	-50.00%	4
5	735	Miscellaneous Production Expenses	23,000	8,000	15,000	187.50%	5
6	813	Other Gas Supply Expenses	(26,000)	1,000	(27,000)	-	6
7		Total Operation	15,000	23,000	(8,000)	-34.78%	7
8	Maintenance						8
9	740	Maintenance Supervision and Engineering	20,000	-	20,000	-	9
10	741	Maintenance of Structures and Improvements	11,000	17,000	(6,000)	-35.29%	10
11	742	Maintenance of Production Equipment	25,000	3,000	22,000	733.33%	11
12		Total Maintenance	56,000	20,000	36,000	180.00%	12
13		**Total Production**	**71,000**	**43,000**	**28,000**	65.12%	13
14	**Transmission**						14
15	Operation						15
16	850	Operation Supervision and Engineering	19,000	-	19,000	-	16
17	856	Mains Expenses	46,000	585,000	(539,000)	-92.14%	17
18		**Total Transmission**	**65,000**	**585,000**	**(520,000)**	-88.89%	18
19	**Distribution**						19
20	Operation						20
21	870	Operation Supervision and Engineering	85,000	-	85,000	-	21
22	871	Distribution Load Dispatching	28,000	6,000	22,000	366.67%	22
23	874	Mains and Services Expenses	611,000	529,000	82,000	15.50%	23
24	878	Meter and House Regulator Expenses	979,000	413,000	566,000	137.05%	24
25	879	Customer Installations Expenses	325,000	136,000	189,000	138.97%	25
26	880	Other Expenses	457,000	1,419,000	(962,000)	-67.79%	26
27	881	Rents	24,000	6,000	18,000	300.00%	27
28		Total Operation	2,509,000	2,509,000	-	-	28
29	Maintenance						29
30	885	Maintenance Supervision and Engineering	167,000	192,000	(25,000)	-13.02%	30
31	886	Maintenance of Structures and Improvements	16,000	7,000	9,000	128.57%	31
32	887	Maintenance of Mains	428,000	368,000	60,000	16.30%	32
33	889	Maintenance of Measuring and Regulating Station - General	23,000	4,000	19,000	475.00%	33
34	891	Maintenance of Measuring and Regulating Station - City Gate	88,000	58,000	30,000	51.72%	34
35	892	Maintenance of Services	563,000	480,000	83,000	17.29%	35
36	893	Maintenance of Meters and House Regulators	28,000	6,000	22,000	366.67%	36
37	894	Maintenance of Other Equipment	1,000	-	1,000	-	37
38		Total Maintenance	1,314,000	1,115,000	199,000	17.85%	38
39		**Total Distribution**	**3,823,000**	**3,624,000**	**199,000**	5.49%	39
40	**Customer Accounts**						40
41	901	Customer Accounts Supervision	1,000	1,000	-	-	41
42	902	Meter Reading Expenses	44,000	43,000	1,000	2.33%	42
43	903	Customer Records and Collection Expenses	2,674,000	3,167,000	(493,000)	-15.57%	43
44	904	Uncollectible Accounts	1,344,000	1,731,000	(387,000)	-22.36%	44
45	905	Miscellaneous Customer Accounts Expenses	1,426,000	1,220,000	206,000	16.89%	45
46		**Total Customer Accounts**	**5,489,000**	**6,162,000**	**(673,000)**	-10.92%	46
47	**Customer Service and Informational Expenses**						47
48	907	Customer Service Supervision	-	-	-	-	48
49	908	Customer Assistance Expenses	44,000	18,000	26,000	144.44%	49
50	909	Information and Instructional Advertising Expense	63,000	217,000	(154,000)	-70.97%	50
51	910	Miscellaneous Customer Service and Informational Expense	65,000	-	65,000	-	51
52		**Total Customer Service and Informational Expenses**	**172,000**	**235,000**	**(63,000)**	-26.81%	52

North Shore Gas Company

Comparison of Budgeted Non-Payroll Expense to Actual

Line No.	Account Number and Description		Historical Year Ended December 31, 2010 Actual	Budget	Variance	% Variance	Line No.
	[A]		[B]	[C]	[D]	[E]	
1	**Administrative and General**						1
2	Operation						2
3	920	Administrative and General Salaries	$ 271,000	$ 319,000	$ (48,000)	-15.05%	3
4	921	Office Supplies and Expense	910,000	1,813,000	(903,000)	-49.81%	4
5	922	Administrative Expenses Transferred - Credit	-	(400,000)	400,000	-100.00%	5
6	923	Outside Services Employed	1,470,000	1,245,000	225,000	18.07%	6
7	924	Property Insurance	36,000	35,000	1,000	2.86%	7
8	925	Injuries and Damages	910,000	1,274,000	(364,000)	-28.57%	8
9	926	Employee Pensions and Benefits	8,402,000	7,297,000	1,105,000	15.14%	9
10	927	Franchise Requirements	1,137,000	1,166,000	(29,000)	-2.49%	10
11	928	Regulatory Commission Expenses	1,026,000	698,000	328,000	46.99%	11
12	929	Duplicate Charges - Credit	(380,000)	-	(380,000)	-	12
13	930.1	General Advertising Expenses	2,000	40,000	(38,000)	-95.00%	13
14	930.2	Miscellaneous General Expenses	14,280,000	15,487,000	(1,207,000)	-7.79%	14
15	931	Rents	921,000	1,178,000	(257,000)	-21.82%	15
16		Total Operation	28,985,000	30,152,000	(1,167,000)	-3.87%	16
17	Maintenance						17
18	932	Maintenance of General Plant	1,000	-	1,000	-	18
19		Total Maintenance	1,000	-	1,000	-	19
20		**Total Administrative and General**	**28,986,000**	**30,152,000**	**(1,166,000)**	-3.87%	20
21		**Total Operation and Maintenance Non-Payroll**	**$ 38,606,000**	**$ 40,801,000**	**$ (2,195,000)**	-5.38%	21

North Shore Gas Company

Comparison of Budgeted Non-Payroll Expense to Actual

Line No.	Account Number and Description		Historical Year Ended December 31, 2011 Actual	Budget	Variance	% Variance	Line No.
	[A]		[B]	[C]	[D]	[E]	
1	**Production**						1
2	Operation						2
3	717	Liquefied Petroleum Gas Expenses	$ 6,000	$ 8,000	$ (2,000)	-25.00%	3
4	735	Miscellaneous Production Expenses	15,000	30,000	(15,000)	-50.00%	4
5		Total Operation	21,000	38,000	(17,000)	-44.74%	5
6	Maintenance						6
7	740	Maintenance Supervision and Engineering	13,000	-	13,000	-	7
8	741	Maintenance of Structures and Improvements	9,000	17,000	(8,000)	-47.06%	8
9	742	Maintenance of Production Equipment	30,000	3,000	27,000	900.00%	9
10		Total Maintenance	52,000	20,000	32,000	160.00%	10
11		**Total Production**	**73,000**	**58,000**	**15,000**	25.86%	11
12	**Transmission**						12
13	Operation						13
14	850	Operation Supervision and Engineering	(19,000)	-	(19,000)	-	14
15	856	Mains Expenses	236,000	590,000	(354,000)	-60.00%	15
16		Total Operation	217,000	590,000	(373,000)	-63.22%	16
17	Maintenance						17
18	863	Maintenance of Mains	116,000	-	116,000	-	18
19		Total Maintenance	116,000	-	116,000	-	19
20		**Total Transmission**	**333,000**	**590,000**	**(257,000)**	-43.56%	20
21	**Distribution**						21
22	Operation						22
23	870	Operation Supervision and Engineering	1,000	551,000	(550,000)	-99.82%	23
24	871	Distribution Load Dispatching	23,000	6,000	17,000	283.33%	24
25	874	Mains and Services Expenses	915,000	547,000	368,000	67.28%	25
26	878	Meter and House Regulator Expenses	1,232,000	427,000	805,000	188.52%	26
27	879	Customer Installations Expenses	465,000	88,000	377,000	428.41%	27
28	880	Other Expenses	846,000	1,310,000	(464,000)	-35.42%	28
29	881	Rents	14,000	6,000	8,000	133.33%	29
30		Total Operation	3,496,000	2,935,000	561,000	19.11%	30
31	Maintenance						31
32	885	Maintenance Supervision and Engineering	50,000	183,000	(133,000)	-72.68%	32
33	886	Maintenance of Structures and Improvements	17,000	177,000	(160,000)	-90.40%	33
34	887	Maintenance of Mains	593,000	540,000	53,000	9.81%	34
35	889	Maintenance of Measuring and Regulating Station - General	21,000	4,000	17,000	425.00%	35
36	891	Maintenance of Measuring and Regulating Station - City Gate	113,000	14,000	99,000	707.14%	36
37	892	Maintenance of Services	592,000	675,000	(83,000)	-12.30%	37
38	893	Maintenance of Meters and House Regulators	38,000	4,000	34,000	850.00%	38
39		Total Maintenance	1,424,000	1,597,000	(173,000)	-10.83%	39
40		**Total Distribution**	**4,920,000**	**4,532,000**	**388,000**	8.56%	40
41	**Customer Accounts**						41
42	901	Customer Accounts Supervision	1,000	5,000	(4,000)	-80.00%	42
43	902	Meter Reading Expenses	46,000	35,000	11,000	31.43%	43
44	903	Customer Records and Collection Expenses	3,033,000	2,552,000	481,000	18.85%	44
45	904	Uncollectible Accounts	1,090,000	1,617,000	(527,000)	-32.59%	45
46	905	Miscellaneous Customer Accounts Expenses	951,000	383,000	568,000	148.30%	46
47		**Total Customer Accounts**	**5,121,000**	**4,592,000**	**529,000**	11.52%	47
48	**Customer Service and Informational Expenses**						48
49	908	Customer Assistance Expenses	120,000	4,000	116,000	2900.00%	49
50	909	Information and Instructional Advertising Expense	10,000	232,000	(222,000)	-95.69%	50
51	910	Miscellaneous Customer Service and Informational Expense	153,000	-	153,000	-	51
52		**Total Customer Service and Informational Expenses**	**283,000**	**236,000**	**47,000**	19.92%	52

North Shore Gas Company

Comparison of Budgeted Non-Payroll Expense to Actual

Line No.	Account Number and Description		Historical Year Ended December 31, 2011 Actual	Budget	Variance	% Variance	Line No.
	[A]		[B]	[C]	[D]	[E]	
1	**Administrative and General**						1
2	Operation						2
3	920	Administrative and General Salaries	$ 131,000	$ 577,000	$ (446,000)	-77.30%	3
4	921	Office Supplies and Expense	1,393,000	1,621,000	(228,000)	-14.07%	4
5	922	Administrative Expenses Transferred - Credit	-	(100,000)	100,000	-100.00%	5
6	923	Outside Services Employed	801,000	999,000	(198,000)	-19.82%	6
7	924	Property Insurance	33,000	33,000	-	-	7
8	925	Injuries and Damages	853,000	1,489,000	(636,000)	-42.71%	8
9	926	Employee Pensions and Benefits	7,408,000	7,649,000	(241,000)	-3.15%	9
10	927	Franchise Requirements	1,081,000	1,061,000	20,000	1.89%	10
11	928	Regulatory Commission Expenses	1,128,000	1,057,000	71,000	6.72%	11
12	929	Duplicate Charges - Credit	(375,000)	-	(375,000)	-	12
13	930.1	General Advertising Expenses	2,000	40,000	(38,000)	-95.00%	13
14	930.2	Miscellaneous General Expenses	11,456,000	18,345,000	(6,889,000)	-37.55%	14
15	931	Rents	884,000	1,076,000	(192,000)	-17.84%	15
16		**Total Administrative and General**	**24,795,000**	**33,847,000**	**(9,052,000)**	-26.74%	16
17		**Total Operation and Maintenance Non-Payroll**	**$ 35,525,000**	**$ 43,855,000**	**$ (8,330,000)**	-18.99%	17

North Shore Gas Company

Comparison of Budgeted Non-Payroll Expense to Actual

Line No.		Account Number and Description	Actual	Budget	Variance	% Variance	Line No.
			Historical Year Ended December 31, 2012				
		[A]	[B]	[C]	[D]	[E]	
1	**Production**						1
2	Operation						2
3	717	Liquefied Petroleum Gas Expenses	$ 2,000	$ 8,000	$ (6,000)	-75.00%	3
4	735	Miscellaneous Production Expenses	14,000	53,000	(39,000)	-73.58%	4
5	813	Other Gas Supply Expenses	40,000	-	40,000	-	5
6		Total Operation	56,000	61,000	(5,000)	-8.20%	6
7	Maintenance						7
8	740	Maintenance Supervision and Engineering	12,000	24,000	(12,000)	-50.00%	8
9	741	Maintenance of Structures and Improvements	8,000	17,000	(9,000)	-52.94%	9
10	742	Maintenance of Production Equipment	84,000	3,000	81,000	2700.00%	10
11		Total Maintenance	104,000	44,000	60,000	136.36%	11
12		**Total Production**	**160,000**	**105,000**	**55,000**	52.38%	12
13	**Transmission**						13
14	Operation						14
15	856	Mains Expenses	102,000	180,000	(78,000)	-43.33%	15
16		Total Operation	102,000	180,000	(78,000)	-43.33%	16
17	Maintenance						17
18	863	Maintenance of Mains	40,000	-	40,000	-	18
19		Total Maintenance	40,000	-	40,000	-	19
20		**Total Transmission**	**142,000**	**180,000**	**(38,000)**	-21.11%	20
21	**Distribution**						21
22	Operation						22
23	870	Operation Supervision and Engineering	2,000	-	2,000	-	23
24	871	Distribution Load Dispatching	109,000	74,000	35,000	47.30%	24
25	874	Mains and Services Expenses	882,000	949,000	(67,000)	-7.06%	25
26	878	Meter and House Regulator Expenses	1,173,000	700,000	473,000	67.57%	26
27	879	Customer Installations Expenses	395,000	154,000	241,000	156.49%	27
28	880	Other Expenses	957,000	1,503,000	(546,000)	-36.33%	28
29	881	Rents	57,000	6,000	51,000	850.00%	29
30		Total Operation	3,575,000	3,386,000	189,000	5.58%	30
31	Maintenance						31
32	885	Maintenance Supervision and Engineering	157,000	178,000	(21,000)	-11.80%	32
33	886	Maintenance of Structures and Improvements	6,000	6,000	-	-	33
34	887	Maintenance of Mains	1,037,000	763,000	274,000	35.91%	34
35	889	Maintenance of Measuring and Regulating Station - General	27,000	4,000	23,000	575.00%	35
36	891	Maintenance of Measuring and Regulating Station - City Gate	112,000	14,000	98,000	700.00%	36
37	892	Maintenance of Services	658,000	695,000	(37,000)	-5.32%	37
38	893	Maintenance of Meters and House Regulators	31,000	4,000	27,000	675.00%	38
39		Total Maintenance	2,028,000	1,664,000	364,000	21.88%	39
40		**Total Distribution**	**5,603,000**	**5,050,000**	**553,000**	10.95%	40
41	**Customer Accounts**						41
42	901	Customer Accounts Supervision	-	48,000	(48,000)	-100.00%	42
43	902	Meter Reading Expenses	42,000	176,000	(134,000)	-76.14%	43
44	903	Customer Records and Collection Expenses	2,857,000	3,062,000	(205,000)	-6.69%	44
45	904	Uncollectible Accounts	914,000	1,479,000	(565,000)	-38.20%	45
46	905	Miscellaneous Customer Accounts Expenses	348,000	716,000	(368,000)	-51.40%	46
47		**Total Customer Accounts**	**4,161,000**	**5,481,000**	**(1,320,000)**	-24.08%	47
48	**Customer Service and Informational Expenses**						48
49	907	Customer Service Supervision	-	7,000	(7,000)	-100.00%	49
50	908	Customer Assistance Expenses	115,000	6,000	109,000	1816.67%	50
51	909	Information and Instructional Advertising Expense	188,000	229,000	(41,000)	-17.90%	51
52	910	Miscellaneous Customer Service and Informational Expense	139,000	44,000	95,000	215.91%	52
53		**Total Customer Service and Informational Expenses**	**442,000**	**286,000**	**156,000**	54.55%	53

North Shore Gas Company

Comparison of Budgeted Non-Payroll Expense to Actual

Line No.	Account Number and Description		Historical Year Ended December 31, 2012 Actual	Budget	Variance	% Variance	Line No.
	[A]		[B]	[C]	[D]	[E]	
1	**Administrative and General**						1
2	Operation						2
3	920	Administrative and General Salaries	$ 120,000	$ 179,000	$ (59,000)	-32.96%	3
4	921	Office Supplies and Expense	1,624,000	2,169,000	(545,000)	-25.13%	4
5	923	Outside Services Employed	821,000	1,367,000	(546,000)	-39.94%	5
6	924	Property Insurance	32,000	29,000	3,000	10.34%	6
7	925	Injuries and Damages	1,334,000	1,221,000	113,000	9.25%	7
8	926	Employee Pensions and Benefits	7,385,000	6,991,000	394,000	5.64%	8
9	927	Franchise Requirements	841,000	934,000	(93,000)	-9.96%	9
10	928	Regulatory Commission Expenses	1,718,000	1,805,000	(87,000)	-4.82%	10
11	929	Duplicate Charges - Credit	(392,000)	-	(392,000)	-	11
12	930.1	General Advertising Expenses	2,000	40,000	(38,000)	-95.00%	12
13	930.2	Miscellaneous General Expenses	6,184,000	15,574,000	(9,390,000)	-60.29%	13
14	931	Rents	789,000	883,000	(94,000)	-10.65%	14
15		**Total Administrative and General**	**20,458,000**	**31,192,000**	**(10,734,000)**	-34.41%	15
16		**Total Operation and Maintenance Non-Payroll**	**$ 30,966,000**	**$ 42,294,000**	**$ (11,328,000)**	-26.78%	16

North Shore Gas Company

Budgeted Payroll Expense (1)

Line No.	Account Number and Description		Historical Year Ended December 31, 2010 Actual	Budget	Variance	% Variance	Line No.
	[A]		[B]	[C]	[D]	[E]	
1	**Production**						1
2	Operation						2
3	710	Operation Supervision and Engineering	$ -	$ 36,000	$ (36,000)	-100.00%	3
4	735	Miscellaneous Production Expenses	73,000	50,000	23,000	46.00%	4
5	813	Other Gas Supply Expenses	26,000	204,000	(178,000)	-87.25%	5
6		Total Operation	99,000	290,000	(191,000)	-65.86%	6
7	Maintenance						7
8	740	Maintenance Supervision and Engineering	83,000	76,000	7,000	9.21%	8
9	741	Maintenance of Structures and Improvements	-	15,000	(15,000)	-100.00%	9
10	742	Maintenance of Production Equipment	32,000	31,000	1,000	3.23%	10
11		Total Maintenance	115,000	122,000	(7,000)	-5.74%	11
12		**Total Production**	**214,000**	**412,000**	**(198,000)**	-48.06%	12
13	**Transmission**						13
14	Operation						14
15	850	Operation Supervision and Engineering	1,000	-	1,000	-	15
16	856	Mains Expense	(1,000)	-	(1,000)	-	16
17		**Total Transmission**	**-**	**-**	**-**	-	17
18	**Distribution**						18
19	Operation						19
20	870	Operation Supervision and Engineering	502,000	716,000	(214,000)	-29.89%	20
21	871	Distribution Load Dispatching	52,000	269,000	(217,000)	-80.67%	21
22	874	Mains and Services Expenses	1,266,000	862,000	404,000	46.87%	22
23	878	Meter and House Regulator Expenses	927,000	817,000	110,000	13.46%	23
24	879	Customer Installations Expenses	303,000	302,000	1,000	0.33%	24
25	880	Other Expenses	2,931,000	2,701,000	230,000	8.52%	25
26		Total Operation	5,981,000	5,667,000	314,000	5.54%	26
27	Maintenance						27
28	885	Maintenance Supervision and Engineering	850,000	957,000	(107,000)	-11.18%	28
29	886	Maintenance of Structures and Improvements	19,000	11,000	8,000	72.73%	29
30	887	Maintenance of Mains	694,000	509,000	185,000	36.35%	30
31	889	Maintenance of Measuring and Regulating Station - General	26,000	-	26,000	-	31
32	891	Maintenance of Measuring and Regulating Station - City Gate	15,000	9,000	6,000	66.67%	32
33	892	Maintenance of Services	642,000	570,000	72,000	12.63%	33
34	893	Maintenance of Meters and House Regulators	24,000	-	24,000	-	34
35		Total Maintenance	2,270,000	2,056,000	214,000	10.41%	35
36		**Total Distribution**	**8,251,000**	**7,723,000**	**528,000**	6.84%	36
37	**Customer Accounts**						37
38	901	Customer Service Supervision	535,000	286,000	249,000	87.06%	38
39	902	Meter Reading Expenses	532,000	523,000	9,000	1.72%	39
40	903	Customer Records and Collection Expenses	1,315,000	1,706,000	(391,000)	-22.92%	40
41	905	Miscellaneous Customer Accounts Expenses	276,000	540,000	(264,000)	-48.89%	41
42		**Total Customer Accounts**	**2,658,000**	**3,055,000**	**(397,000)**	-13.00%	42
43	**Customer Service and Informational Expenses**						43
44	907	Customer Service Supervision	113,000	91,000	22,000	24.18%	44
45	908	Customer Assistance Expenses	203,000	152,000	51,000	33.55%	45
46	909	Information and Instructional Advertising Expenses	18,000	110,000	(92,000)	-83.64%	46
47		**Total Customer Service and Informational Expenses**	**334,000**	**353,000**	**(19,000)**	-5.38%	47
48	**Administrative and General**						48
49	Operation						49
50	920	Administrative and General Salaries	5,370,000	4,386,000	984,000	22.44%	50
51	921	Office Supplies and Expenses	5,000	-	5,000	-	51
52	922	Administrative Expenses Transferred - Credit	-	(599,000)	599,000	-100.00%	52
53	925	Injuries and Damages	1,000	-	1,000	-	53
54	926	Employee Pensions and Benefits	(135,000)	(116,000)	(19,000)	16.38%	54
55	930.1	General Advertising Expenses	9,000	-	9,000	-	55
56	930.2	Miscellaneous General Expenses	38,000	-	38,000	-	56
57		**Total Administrative and General**	**5,288,000**	**3,671,000**	**1,617,000**	44.05%	57
58		**Total Operation and Maintenance Payroll**	**$ 16,745,000**	**$ 15,214,000**	**$ 1,531,000**	10.06%	58

Note: (1) Payroll expense includes labor and incentives direct billed or allocated to NS by affiliates consistent with amounts shown on schedule C-11.1.

North Shore Gas Company

Budgeted Payroll Expense (1)

Line No.	Account Number and Description		Actual (Historical Year Ended December 31, 2011)	Budget	Variance	% Variance	Line No.
	[A]		[B]	[C]	[D]	[E]	
1	**Production**						1
2	Operation						2
3	710	Operation Supervision and Engineering	$ -	$ 40,000	$ (40,000)	-100.00%	3
4	735	Miscellaneous Production Expenses	48,000	45,000	3,000	6.67%	4
5		Total Operation	48,000	85,000	(37,000)	-43.53%	5
6	Maintenance						6
7	740	Maintenance Supervision and Engineering	96,000	80,000	16,000	20.00%	7
8	741	Maintenance of Structures and Improvements	-	11,000	(11,000)	-100.00%	8
9	742	Maintenance of Production Equipment	22,000	36,000	(14,000)	-38.89%	9
10		Total Maintenance	118,000	127,000	(9,000)	-7.09%	10
11		**Total Production**	**166,000**	**212,000**	**(46,000)**	-21.70%	11
12	**Transmission**						12
13	Maintenance						13
14	863	Maintenance Supervision and Engineering	23,000	-	23,000	-	14
15		**Total Transmission**	**23,000**	**-**	**23,000**	-	15
16	**Distribution**						16
17	Operation						17
18	870	Operation Supervision and Engineering	389,000	563,000	(174,000)	-30.91%	18
19	871	Distribution Load Dispatching	28,000	39,000	(11,000)	-28.21%	19
20	874	Mains and Services Expenses	1,367,000	910,000	457,000	50.22%	20
21	878	Meter and House Regulator Expenses	892,000	869,000	23,000	2.65%	21
22	879	Customer Installations Expenses	395,000	283,000	112,000	39.58%	22
23	880	Other Expenses	3,626,000	3,022,000	604,000	19.99%	23
24		Total Operation	6,697,000	5,686,000	1,011,000	17.78%	24
25	Maintenance						25
26	885	Maintenance Supervision and Engineering	47,000	201,000	(154,000)	-76.62%	26
27	886	Maintenance of Structures and Improvements	23,000	19,000	4,000	21.05%	27
28	887	Maintenance of Mains	723,000	565,000	158,000	27.96%	28
29	889	Maintenance of Measuring and Regulating Station - General	39,000	-	39,000	-	29
30	891	Maintenance of Measuring and Regulating Station - City Gate	12,000	13,000	(1,000)	-7.69%	30
31	892	Maintenance of Services	619,000	576,000	43,000	7.47%	31
32	893	Maintenance of Meters and House Regulators	27,000	-	27,000	-	32
33		Total Maintenance	1,490,000	1,374,000	116,000	8.44%	33
34		**Total Distribution**	**8,187,000**	**7,060,000**	**1,127,000**	15.96%	34
35	**Customer Accounts**						35
36	901	Customer Service Supervision	490,000	232,000	258,000	111.21%	36
37	902	Meter Reading Expenses	559,000	455,000	104,000	22.86%	37
38	903	Customer Records and Collection Expenses	1,233,000	1,457,000	(224,000)	-15.37%	38
39	905	Miscellaneous Customer Accounts Expenses	249,000	241,000	8,000	3.32%	39
40		**Total Customer Accounts**	**2,531,000**	**2,385,000**	**146,000**	6.12%	40
41	**Customer Service and Informational Expenses**						41
42	907	Customer Service Supervision	93,000	14,000	79,000	564.29%	42
43	908	Customer Assistance Expenses	251,000	210,000	41,000	19.52%	43
44	909	Information and Instructional Advertising Expenses	-	65,000	(65,000)	-100.00%	44
45		**Total Customer Service and Informational Expenses**	**344,000**	**289,000**	**55,000**	19.03%	45
46	**Administrative and General**						46
47	Operation						47
48	920	Administrative and General Salaries	5,018,000	4,698,000	320,000	6.81%	48
49	922	Administrative Expenses Transferred - Credit	-	(125,000)	125,000	-100.00%	49
50	926	Employee Pensions and Benefits	(36,000)	-	(36,000)	-	50
51	930.1	General Advertising Expenses	8,000	11,000	(3,000)	-27.27%	51
52	930.2	Miscellaneous General Expenses	14,000	-	14,000	-	52
53		**Total Administrative and General**	**5,004,000**	**4,584,000**	**420,000**	9.16%	53
54		**Total Operation and Maintenance Payroll**	**$ 16,255,000**	**$ 14,530,000**	**$ 1,725,000**	11.87%	54

Note: (1) Payroll expense includes labor and incentives direct billed or allocated to NS by affiliates consistent with amounts shown on schedule C-11.1.

North Shore Gas Company

Budgeted Payroll Expense (1)

Line No.	Account Number	Description	Historical Year Ended December 31, 2012 Actual	Budget	Variance	% Variance	Test Year Ending December 31, 2015	Line No.
	[A]		[B]	[C]	[D]	[E]	[F]	
1	**Production**							1
2	Operation							2
3	735	Miscellaneous Production Expenses	$ 52,000	$ 43,000	$ 9,000	20.93%	$ 141,000	3
4	813	Other Gas Supply Expenses	239,000	-	239,000	-	271,000	4
5		Total Operation	291,000	43,000	248,000	576.74%	412,000	5
6	Maintenance							6
7	740	Maintenance Supervision and Engineering	148,000	127,000	21,000	16.54%	254,000	7
8	742	Maintenance of Production Equipment	33,000	44,000	(11,000)	-25.00%	45,000	8
9		Total Maintenance	181,000	171,000	10,000	5.85%	299,000	9
10		**Total Production**	**472,000**	**214,000**	**258,000**	120.56%	**711,000**	10
11	**Transmission**							11
12	Maintenance							12
13	863	Maintenance Supervision and Engineering	7,000	-	7,000	-	-	13
14		**Total Transmission**	**7,000**	**-**	**7,000**	-	**-**	14
15	**Distribution**							15
16	Operation							16
17	870	Operation Supervision and Engineering	377,000	855,000	(478,000)	-55.91%	367,000	17
18	871	Distribution Load Dispatching	46,000	243,000	(197,000)	-81.07%	69,000	18
19	874	Mains and Services Expenses	1,604,000	925,000	679,000	73.41%	1,614,000	19
20	878	Meter and House Regulator Expenses	1,040,000	885,000	155,000	17.51%	916,000	20
21	879	Customer Installations Expenses	399,000	288,000	111,000	38.54%	431,000	21
22	880	Other Expenses	4,077,000	2,900,000	1,177,000	40.59%	4,854,000	22
23		Total Operation	7,543,000	6,096,000	1,447,000	23.74%	8,251,000	23
24	Maintenance							24
25	885	Maintenance Supervision and Engineering	142,000	220,000	(78,000)	-35.45%	293,000	25
26	886	Maintenance of Structures and Improvements	4,000	68,000	(64,000)	-94.12%	8,000	26
27	887	Maintenance of Mains	809,000	616,000	193,000	31.33%	742,000	27
28	889	Maintenance of Measuring and Regulating Station - General	36,000	-	36,000	-	-	28
29	891	Maintenance of Measuring and Regulating Station - City Gate	19,000	14,000	5,000	35.71%	58,000	29
30	892	Maintenance of Services	759,000	592,000	167,000	28.21%	720,000	30
31	893	Maintenance of Meters and House Regulators	33,000	-	33,000	-	-	31
32		Total Maintenance	1,802,000	1,510,000	292,000	19.34%	1,821,000	32
33		**Total Distribution**	**9,345,000**	**7,606,000**	**1,739,000**	22.86%	**10,072,000**	33
34	**Customer Accounts**							34
35	901	Customer Service Supervision	476,000	247,000	229,000	92.71%	213,000	35
36	902	Meter Reading Expenses	529,000	469,000	60,000	12.79%	690,000	36
37	903	Customer Records and Collection Expenses	1,214,000	1,632,000	(418,000)	-25.61%	1,459,000	37
38	905	Miscellaneous Customer Accounts Expenses	184,000	290,000	(106,000)	-36.55%	149,000	38
39		**Total Customer Accounts**	**2,403,000**	**2,638,000**	**(235,000)**	-8.91%	**2,511,000**	39
40	**Customer Service and Informational Expenses**							40
41	907	Customer Service Supervision	65,000	135,000	(70,000)	-51.85%	46,000	41
42	908	Customer Assistance Expenses	266,000	79,000	187,000	236.71%	276,000	42
43	909	Information and Instructional Advertising Expenses	21,000	67,000	(46,000)	-68.66%	15,000	43
44		**Total Customer Service and Informational Expenses**	**352,000**	**281,000**	**71,000**	25.27%	**337,000**	44
45	**Administrative and General**							45
46	Operation							46
47	920	Administrative and General Salaries	4,557,000	5,537,000	(980,000)	-17.70%	6,006,000	47
48	925	Injuries and Damages	-	4,000	(4,000)	-100.00%	-	48
49	926	Employee Pensions and Benefits	(146,000)	56,000	(202,000)	-360.71%	75,000	49
50	930.1	General Advertising Expenses	-	14,000	(14,000)	-100.00%	12,000	50
51	930.2	Miscellaneous General Expenses	8,000	50,000	(42,000)	-84.00%	9,000	51
52		**Total Administrative and General**	**4,419,000**	**5,661,000**	**(1,242,000)**	-21.94%	**6,102,000**	52
53		**Total Operation and Maintenance Payroll**	**$ 16,998,000**	**$ 16,400,000**	**$ 598,000**	3.65%	**$ 19,733,000**	53

Note: (1) Payroll expense includes labor and incentives direct billed or allocated to NS by affiliates consistent with amounts shown on schedule C-11.1.

North Shore Gas Company

Budgeted Number of Employees

Test Year Ending December 31, 2015

Line No.	Department [A]	January Budget [B]	February Budget [C]	March Budget [D]	April Budget [E]	May Budget [F]	June Budget [G]	July Budget [H]	August Budget [I]	September Budget [J]	October Budget [K]	November Budget [L]	December Budget [M]	Line No.
1	**Operations**													1
2	B25 Meter Reading													2
3	Full Time Employees (a)	12	12	12	12	12	12	12	12	12	12	12	12	3
4	Part Time Employees	0	0	0	0	0	0	0	0	0	0	0	0	4
5	Full Time Equivalents for PT Employees (b)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5
6	Total Full Time Equivalents (a)+(b)	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	6
7	B45 Distribution Design													7
8	Full Time Employees (a)	7	7	7	7	7	7	7	7	7	7	7	7	8
9	Part Time Employees	0	0	0	0	0	0	0	0	0	0	0	0	9
10	Full Time Equivalents for PT Employees (b)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	10
11	Total Full Time Equivalents (a)+(b)	7.00	7.00	7.00	7.00	7.00	7.00	7.00	7.00	7.00	7.00	7.00	7.00	11
12	B53 Production Department													12
13	Full Time Employees (a)	3	3	3	3	3	3	3	3	3	3	3	3	13
14	Part Time Employees	0	0	0	0	0	0	0	0	0	0	0	0	14
15	Full Time Equivalents for PT Employees (b)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	15
16	Total Full Time Equivalents (a)+(b)	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	16
17	B80 North Shore Operations													17
18	Full Time Employees (a)	147	147	147	147	148	148	148	148	147	147	147	147	18
19	Part Time Employees	1	1	1	1	1	1	1	1	1	1	1	1	19
20	Full Time Equivalents for PT Employees (b)	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	20
21	Total Full Time Equivalents (a)+(b)	147.68	147.68	147.68	147.68	148.68	148.68	148.68	148.68	147.68	147.68	147.68	147.68	21
22	Total Operations													22
23	Full Time Employees (a)	169	169	169	169	170	170	170	170	169	169	169	169	23
24	Part Time Employees	1	1	1	1	1	1	1	1	1	1	1	1	24
25	Full Time Equivalents for PT Employees (b)	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	25
26	Total Full Time Equivalents (a)+(b)	169.68	169.68	169.68	169.68	170.68	170.68	170.68	170.68	169.68	169.68	169.68	169.68	26
27	**Fleet and Supply Chain**													27
28	B02 Fleet													28
29	Full Time Employees (a)	6	6	6	6	6	6	6	6	6	6	6	6	29
30	Part Time Employees	0	0	0	0	0	0	0	0	0	0	0	0	30
31	Full Time Equivalents for PT Employees (b)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	31
32	Total Full Time Equivalents (a)+(b)	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	32
33	B03 Supply Chain													33
34	Full Time Employees (a)	2	2	2	2	2	2	2	2	2	2	2	2	34
35	Part Time Employees	0	0	0	0	0	0	0	0	0	0	0	0	35
36	Full Time Equivalents for PT Employees (b)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	36
37	Total Full Time Equivalents (a)+(b)	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	37
38	Total Fleet and Supply Chain													38
39	Full Time Employees (a)	8	8	8	8	8	8	8	8	8	8	8	8	39
40	Part Time Employees	0	0	0	0	0	0	0	0	0	0	0	0	40
41	Full Time Equivalents for PT Employees (b)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	41
42	Total Full Time Equivalents (a)+(b)	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	42
43	**Total North Shore Gas Company**													43
44	Full Time Employees (a)	177	177	177	177	178	178	178	178	177	177	177	177	44
45	Part Time Employees	1	1	1	1	1	1	1	1	1	1	1	1	45
46	Full Time Equivalents for PT Employees (b)	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	46
47	Total Full Time Equivalents (a)+(b)	177.68	177.68	177.68	177.68	178.68	178.68	178.68	178.68	177.68	177.68	177.68	177.68	47

North Shore Gas Company

Budgeted Number of Employees

Historical Year Ended December 31, 2012

Line No.	Department [A]	January Budget [B]	February Budget [C]	March Budget [D]	April Budget [E]	May Budget [F]	June Budget [G]	July Budget [H]	August Budget [I]	September Budget [J]	October Budget [K]	November Budget [L]	December Budget [M]	Line No.
1	**Operations**													1
2	B25 Meter Reading													2
3	Full Time Employees (a)	8	8	8	8	8	8	8	8	8	8	8	8	3
4	Part Time Employees	0	0	0	0	0	0	0	0	0	0	0	0	4
5	Full Time Equivalents for PT Employees (b)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5
6	Total Full Time Equivalents (a)+(b)	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	6
7	B45 Distribution Design													7
8	Full Time Employees (a)	4	4	4	4	4	4	4	4	4	4	4	4	8
9	Part Time Employees	0	0	0	0	0	0	0	0	0	0	0	0	9
10	Full Time Equivalents for PT Employees (b)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	10
11	Total Full Time Equivalents (a)+(b)	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	11
12	B53 Production Department													12
13	Full Time Employees (a)	3	3	3	3	3	3	3	3	3	3	3	3	13
14	Part Time Employees	0	0	0	0	0	0	0	0	0	0	0	0	14
15	Full Time Equivalents for PT Employees (b)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	15
16	Total Full Time Equivalents (a)+(b)	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	16
17	B80 North Shore Operations													17
18	Full Time Employees (a)	146	146	146	146	146	146	146	146	146	146	146	146	18
19	Part Time Employees	1	1	1	1	1	1	1	1	1	1	1	1	19
20	Full Time Equivalents for PT Employees (b)	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	20
21	Total Full Time Equivalents (a)+(b)	146.68	146.68	146.68	146.68	146.68	146.68	146.68	146.68	146.68	146.68	146.68	146.68	21
22	Total Operations													22
23	Full Time Employees (a)	161	161	161	161	161	161	161	161	161	161	161	161	23
24	Part Time Employees	1	1	1	1	1	1	1	1	1	1	1	1	24
25	Full Time Equivalents for PT Employees (b)	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	25
26	Total Full Time Equivalents (a)+(b)	161.68	161.68	161.68	161.68	161.68	161.68	161.68	161.68	161.68	161.68	161.68	161.68	26
27	**Fleet and Supply Chain**													27
28	B02 Fleet													28
29	Full Time Employees (a)	6	6	6	6	6	6	6	6	6	6	6	6	29
30	Part Time Employees	0	0	0	0	0	0	0	0	0	0	0	0	30
31	Full Time Equivalents for PT Employees (b)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	31
32	Total Full Time Equivalents (a)+(b)	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	32
33	B03 Supply Chain													33
34	Full Time Employees (a)	3	3	3	3	3	3	3	3	3	3	3	3	34
35	Part Time Employees	0	0	0	0	0	0	0	0	0	0	0	0	35
36	Full Time Equivalents for PT Employees (b)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	36
37	Total Full Time Equivalents (a)+(b)	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	37
38	Total Fleet and Supply Chain													38
39	Full Time Employees (a)	9	9	9	9	9	9	9	9	9	9	9	9	39
40	Part Time Employees	0	0	0	0	0	0	0	0	0	0	0	0	40
41	Full Time Equivalents for PT Employees (b)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	41
42	Total Full Time Equivalents (a)+(b)	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	42
43	**Total North Shore Gas Company**													43
44	Full Time Employees (a)	170	170	170	170	170	170	170	170	170	170	170	170	44
45	Part Time Employees	1	1	1	1	1	1	1	1	1	1	1	1	45
46	Full Time Equivalents for PT Employees (b)	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	46
47	Total Full Time Equivalents (a)+(b)	170.68	170.68	170.68	170.68	170.68	170.68	170.68	170.68	170.68	170.68	170.68	170.68	47

North Shore Gas Company

Budgeted Number of Employees

Historical Year Ended December 31, 2011

Line No.	Department	January Budget	February Budget	March Budget	April Budget	May Budget	June Budget	July Budget	August Budget	September Budget	October Budget	November Budget	December Budget	Line No.
	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]	
1	**Operations**													1
2	B25 Meter Reading													2
3	Full Time Employees (a)	8	8	8	8	8	8	8	8	8	8	8	8	3
4	Part Time Employees	0	0	0	0	0	0	0	0	0	0	0	0	4
5	Full Time Equivalents for PT Employees (b)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5
6	Total Full Time Equivalents (a)+(b)	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	6
7	B53 Production Department													7
8	Full Time Employees (a)	3	3	3	3	3	3	3	3	3	3	3	3	8
9	Part Time Employees	0	0	0	0	0	0	0	0	0	0	0	0	9
10	Full Time Equivalents for PT Employees (b)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	10
11	Total Full Time Equivalents (a)+(b)	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	11
12	B80 North Shore Operations													12
13	Full Time Employees (a)	146	146	146	146	146	146	146	146	146	146	146	146	13
14	Part Time Employees	1	1	1	1	1	1	1	1	1	1	1	1	14
15	Full Time Equivalents for PT Employees (b)	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	15
16	Total Full Time Equivalents (a)+(b)	146.68	146.68	146.68	146.68	146.68	146.68	146.68	146.68	146.68	146.68	146.68	146.68	16
17	Total Operations													17
18	Full Time Employees (a)	157	157	157	157	157	157	157	157	157	157	157	157	18
19	Part Time Employees	1	1	1	1	1	1	1	1	1	1	1	1	19
20	Full Time Equivalents for PT Employees (b)	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	20
21	Total Full Time Equivalents (a)+(b)	157.68	157.68	157.68	157.68	157.68	157.68	157.68	157.68	157.68	157.68	157.68	157.68	21
22	**Fleet and Supply Chain**													22
23	B02 Fleet													23
24	Full Time Employees (a)	6	6	6	6	6	6	6	6	6	6	6	6	24
25	Part Time Employees	0	0	0	0	0	0	0	0	0	0	0	0	25
26	Full Time Equivalents for PT Employees (b)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	26
27	Total Full Time Equivalents (a)+(b)	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	27
28	B03 Supply Chain													28
29	Full Time Employees (a)	3	3	3	3	3	3	3	3	3	3	3	3	29
30	Part Time Employees	0	0	0	0	0	0	0	0	0	0	0	0	30
31	Full Time Equivalents for PT Employees (b)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	31
32	Total Full Time Equivalents (a)+(b)	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	32
33	Total Fleet and Supply Chain													33
34	Full Time Employees (a)	9	9	9	9	9	9	9	9	9	9	9	9	34
35	Part Time Employees	0	0	0	0	0	0	0	0	0	0	0	0	35
36	Full Time Equivalents for PT Employees (b)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	36
37	Total Full Time Equivalents (a)+(b)	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	37
38	**Total North Shore Gas Company**													38
39	Full Time Employees (a)	166	166	166	166	166	166	166	166	166	166	166	166	39
40	Part Time Employees	1	1	1	1	1	1	1	1	1	1	1	1	40
41	Full Time Equivalents for PT Employees (b)	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	41
42	Total Full Time Equivalents (a)+(b)	166.68	166.68	166.68	166.68	166.68	166.68	166.68	166.68	166.68	166.68	166.68	166.68	42

North Shore Gas Company

Budgeted Number of Employees

Historical Year Ended December 31, 2010

Line No.	Department	January Budget	February Budget	March Budget	April Budget	May Budget	June Budget	July Budget	August Budget	September Budget	October Budget	November Budget	December Budget	Line No.
	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]	
1	**Operations**													1
2	B25 Meter Reading													2
3	Full Time Employees (a)	8	8	8	8	8	8	8	8	8	8	8	8	3
4	Part Time Employees	2	2	2	2	2	2	2	2	2	2	2	2	4
5	Full Time Equivalents for PT Employees (b)	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	5
6	Total Full Time Equivalents (a)+(b)	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	6
7	B53 Production Department													7
8	Full Time Employees (a)	3	3	3	3	3	3	3	3	3	3	3	3	8
9	Part Time Employees	0	0	0	0	0	0	0	0	0	0	0	0	9
10	Full Time Equivalents for PT Employees (b)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	10
11	Total Full Time Equivalents (a)+(b)	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	11
12	B80 North Shore Operations													12
13	Full Time Employees (a)	149	149	149	149	149	149	149	149	149	149	149	149	13
14	Part Time Employees	0	0	0	0	0	0	0	0	0	0	0	0	14
15	Full Time Equivalents for PT Employees (b)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	15
16	Total Full Time Equivalents (a)+(b)	149.00	149.00	149.00	149.00	149.00	149.00	149.00	149.00	149.00	149.00	149.00	149.00	16
17	Total Operations													17
18	Full Time Employees (a)	160	160	160	160	160	160	160	160	160	160	160	160	18
19	Part Time Employees	2	2	2	2	2	2	2	2	2	2	2	2	19
20	Full Time Equivalents for PT Employees (b)	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	20
21	Total Full Time Equivalents (a)+(b)	161.00	161.00	161.00	161.00	161.00	161.00	161.00	161.00	161.00	161.00	161.00	161.00	21
22	**Fleet and Supply Chain**													22
23	B02 Fleet													23
24	Full Time Employees (a)	6	6	6	6	6	6	6	6	6	6	6	6	24
25	Part Time Employees	0	0	0	0	0	0	0	0	0	0	0	0	25
26	Full Time Equivalents for PT Employees (b)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	26
27	Total Full Time Equivalents (a)+(b)	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	27
28	B03 Supply Chain													28
29	Full Time Employees (a)	3	3	3	3	3	3	3	3	3	3	3	3	29
30	Part Time Employees	0	0	0	0	0	0	0	0	0	0	0	0	30
31	Full Time Equivalents for PT Employees (b)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	31
32	Total Full Time Equivalents (a)+(b)	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	32
33	Total Fleet and Supply Chain													33
34	Full Time Employees (a)	9	9	9	9	9	9	9	9	9	9	9	9	34
35	Part Time Employees	0	0	0	0	0	0	0	0	0	0	0	0	35
36	Full Time Equivalents for PT Employees (b)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	36
37	Total Full Time Equivalents (a)+(b)	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	37
38	**Total North Shore Gas Company**													38
39	Full Time Employees (a)	169	169	169	169	169	169	169	169	169	169	169	169	39
40	Part Time Employees	2	2	2	2	2	2	2	2	2	2	2	2	40
41	Full Time Equivalents for PT Employees (b)	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	41
42	Total Full Time Equivalents (a)+(b)	170.00	170.00	170.00	170.00	170.00	170.00	170.00	170.00	170.00	170.00	170.00	170.00	42

North Shore Gas Company

Forecasted Property Taxes

Line No.	County	Forecasted Year Ending December 31, 2013 (1) Equalized Assessed Value	Forecasted Year Ending December 31, 2013 (1) Effective Tax Rate	Budget Year Ending December 31, 2014 (2) Equalized Assessed Value	Budget Year Ending December 31, 2014 (2) Effective Tax Rate	Test Year Ending December 31, 2015 Equalized Assessed Value	Test Year Ending December 31, 2015 Effective Tax Rate	Basis for Escalation Rate Used in Test Year
	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]
1	Lake	$2,305,113	11.246%	$2,305,113	11.482%	$2,305,113	11.758%	The Company assumed an increase in the effective tax rate of 2.1% for 2013 and 2014 and 2.4% for 2015.

2 Description of Methodology Used to Derive Forecasted Amounts Reflected on Schedule C-19 (Property Taxes):

3 The company used the last known liability paid (2012 in 2013) as the starting point, and estimated the taxes
4 based upon the taxes paid using the inflation assumptions of 2.1% for 2013 and 2014 and 2.4% for 2015.

5 Property tax recoveries obtained from any appeals process for 2013, 2012, 2011

Line No.		2013	2012	2011
		[A]	[B]	[C]
6	Amount Recovered	$0	$493	$0

Notes: (1) Includes six months of actual and six months of forecasted data.
(2) Includes zero months of actual and twelve months of forecasted data.

North Shore Gas Company

Comparison of Actual Financial Results to
the Originally Approved Forecast

		December, 2012				
Line No.	Account	Actual	Budget	Actual Vs. Budget	Percentage Variation Actual vs. Budget	Line No.
	[A]	[B]	[C]	[D]	[E]	
1	Operating Revenues	$ 21,634,000	$31,538,000	$ (9,904,000)	(31.4%)	1
2	Operating Expenses:					2
3	Cost Of Gas	12,921,000	21,303,000	(8,382,000)	(39.3%)	3
4	Other Operation and Maintenance	5,182,000	5,958,000	(776,000)	(13.0%)	4
5	Depreciation Expense	844,000	890,000	(46,000)	(5.2%)	5
6	Amortization Of Other Limited Term Gas Plant	-	-	-	-	6
7	Taxes Other Than Income	388,000	241,000	147,000	61.0%	7
8	Federal Income Taxes - Current	1,380,000	445,000	935,000	210.1%	8
9	State Income Taxes - Current	157,000	143,000	14,000	9.8%	9
10	Deferred Income Taxes	(392,000)	537,000	(929,000)	(173.0%)	10
11	Investment Tax Credit	(57,000)	3,000	(60,000)	(2000.0%)	11
12	Total Operating Expenses	20,423,000	29,520,000	(9,097,000)	(30.8%)	12
13	Operating Income	1,211,000	2,018,000	(807,000)	(40.0%)	13
14	Income From Utility Plant Leased to Others	-	-	-	-	14
15	Utility Operating Income	1,211,000	2,018,000	(807,000)	(40.0%)	15
16	Other Income, Net of Income Deductions	(58,000)	17,000	(75,000)	(441.2%)	16
17	Income Before Interest Charges	1,153,000	2,035,000	(882,000)	(43.3%)	17
18	Interest Charges	305,000	372,000	(67,000)	(18.0%)	18
19	Net Income	$ 848,000	$ 1,663,000	$ (815,000)	(49.0%)	19

North Shore Gas Company

Comparison of Actual Financial Results to
the Originally Approved Forecast

Line No.	Account	January, 2013 Actual	Budget	Actual Vs. Budget	Percentage Variation Actual vs. Budget	Line No.
	[A]	[B]	[C]	[D]	[E]	
1	Operating Revenues	$ 27,985,000	$31,033,000	$ (3,048,000)	(9.8%)	1
2	Operating Expenses:					2
3	Cost Of Gas	17,960,000	21,303,000	(3,343,000)	(15.7%)	3
4	Other Operation and Maintenance	5,974,000	5,410,000	564,000	10.4%	4
5	Depreciation Expense	851,000	888,000	(37,000)	(4.2%)	5
6	Amortization Of Other Limited Term Gas Plant	-	-	-	-	6
7	Taxes Other Than Income	307,000	277,000	30,000	10.8%	7
8	Federal Income Taxes - Current	456,000	427,000	29,000	6.8%	8
9	State Income Taxes - Current	96,000	62,000	34,000	54.8%	9
10	Deferred Income Taxes	499,000	666,000	(167,000)	(25.1%)	10
11	Investment Tax Credit	-	-	-	-	11
12	Total Operating Expenses	26,143,000	29,033,000	(2,890,000)	(10.0%)	12
13	Operating Income	1,842,000	2,000,000	(158,000)	(7.9%)	13
14	Income From Utility Plant Leased to Others	-	-	-	-	14
15	Utility Operating Income	1,842,000	2,000,000	(158,000)	(7.9%)	15
16	Other Income, Net of Income Deductions	7,000	(1,000)	8,000	(800.0%)	16
17	Income Before Interest Charges	1,849,000	1,999,000	(150,000)	(7.5%)	17
18	Interest Charges	312,000	320,000	(8,000)	(2.5%)	18
19	Net Income	$ 1,537,000	$ 1,679,000	$ (142,000)	(8.5%)	19

North Shore Gas Company

Comparison of Actual Financial Results to
the Originally Approved Forecast

Line No.	Account	February, 2013 Actual	Budget	Actual Vs. Budget	Percentage Variation Actual vs. Budget	Line No.
	[A]	[B]	[C]	[D]	[E]	
1	Operating Revenues	$ 25,372,000	$ 26,421,000	$ (1,049,000)	(4.0%)	1
2	Operating Expenses:					2
3	Cost Of Gas	16,720,000	17,678,000	(958,000)	(5.4%)	3
4	Other Operation and Maintenance	4,352,000	4,869,000	(517,000)	(10.6%)	4
5	Depreciation Expense	854,000	890,000	(36,000)	(4.0%)	5
6	Amortization Of Other Limited Term Gas Plant	-	-	-	-	6
7	Taxes Other Than Income	294,000	277,000	17,000	6.1%	7
8	Federal Income Taxes - Current	729,000	273,000	456,000	167.0%	8
9	State Income Taxes - Current	178,000	34,000	144,000	423.5%	9
10	Deferred Income Taxes	260,000	666,000	(406,000)	(61.0%)	10
11	Investment Tax Credit	-	-	-	-	11
12	Total Operating Expenses	23,387,000	24,687,000	(1,300,000)	(5.3%)	12
13	Operating Income	1,985,000	1,734,000	251,000	14.5%	13
14	Income From Utility Plant Leased to Others	-	-	-	-	14
15	Utility Operating Income	1,985,000	1,734,000	251,000	14.5%	15
16	Other Income, Net of Income Deductions	(9,000)	1,000	(10,000)	(1000.0%)	16
17	Income Before Interest Charges	1,976,000	1,735,000	241,000	13.9%	17
18	Interest Charges	309,000	317,000	(8,000)	(2.5%)	18
19	Net Income	$ 1,667,000	$ 1,418,000	$ 249,000	17.6%	19

North Shore Gas Company

Comparison of Actual Financial Results to
the Originally Approved Forecast

		March, 2013				
Line No.	Account	Actual	Budget	Actual Vs. Budget	Percentage Variation Actual vs. Budget	Line No.
	[A]	[B]	[C]	[D]	[E]	
1	Operating Revenues	$ 24,332,000	$ 21,736,000	$ 2,596,000	11.9%	1
2	Operating Expenses:					2
3	Cost Of Gas	14,254,000	13,365,000	889,000	6.7%	3
4	Other Operation and Maintenance	4,096,000	5,401,000	(1,305,000)	(24.2%)	4
5	Depreciation Expense	862,000	893,000	(31,000)	(3.5%)	5
6	Amortization Of Other Limited Term Gas Plant	-	-	-	-	6
7	Taxes Other Than Income	263,000	328,000	(65,000)	(19.8%)	7
8	Federal Income Taxes - Current	96,000	(54,000)	150,000	(277.8%)	8
9	State Income Taxes - Current	(58,000)	(29,000)	(29,000)	100.0%	9
10	Deferred Income Taxes	1,821,000	670,000	1,151,000	171.8%	10
11	Investment Tax Credit	-	-	-	-	11
12	Total Operating Expenses	21,334,000	20,574,000	760,000	3.7%	12
13	Operating Income	2,998,000	1,162,000	1,836,000	158.0%	13
14	Income From Utility Plant Leased to Others	-	-	-	-	14
15	Utility Operating Income	2,998,000	1,162,000	1,836,000	158.0%	15
16	Other Income, Net of Income Deductions	(3,000)	(10,000)	7,000	(70.0%)	16
17	Income Before Interest Charges	2,995,000	1,152,000	1,843,000	160.0%	17
18	Interest Charges	351,000	313,000	38,000	12.1%	18
19	Net Income	$ 2,644,000	$ 839,000	$ 1,805,000	215.1%	19

North Shore Gas Company

Comparison of Actual Financial Results to
the Originally Approved Forecast

Line No.	Account	April, 2013 Actual	Budget	Actual Vs. Budget	Percentage Variation Actual vs. Budget	Line No.
	[A]	[B]	[C]	[D]	[E]	
1	Operating Revenues	$ 16,342,000	$ 14,713,000	$ 1,629,000	11.1%	1
2	Operating Expenses:					2
3	Cost Of Gas	9,274,000	7,648,000	1,626,000	21.3%	3
4	Other Operation and Maintenance	4,407,000	4,627,000	(220,000)	(4.8%)	4
5	Depreciation Expense	867,000	897,000	(30,000)	(3.3%)	5
6	Amortization Of Other Limited Term Gas Plant	-	-	-	-	6
7	Taxes Other Than Income	240,000	293,000	(53,000)	(18.1%)	7
8	Federal Income Taxes - Current	(699,000)	(228,000)	(471,000)	206.6%	8
9	State Income Taxes - Current	(256,000)	(60,000)	(196,000)	326.7%	9
10	Deferred Income Taxes	1,471,000	670,000	801,000	119.6%	10
11	Investment Tax Credit	-	-	-	-	11
12	Total Operating Expenses	15,304,000	13,847,000	1,457,000	10.5%	12
13	Operating Income	1,038,000	866,000	172,000	19.9%	13
14	Income From Utility Plant Leased to Others	-	-	-	-	14
15	Utility Operating Income	1,038,000	866,000	172,000	19.9%	15
16	Other Income, Net of Income Deductions	-	6,000	(6,000)	(100.0%)	16
17	Income Before Interest Charges	1,038,000	872,000	166,000	19.0%	17
18	Interest Charges	307,000	313,000	(6,000)	(1.9%)	18
19	Net Income	$ 731,000	$ 559,000	$ 172,000	30.8%	19

North Shore Gas Company

Comparison of Actual Financial Results to
the Originally Approved Forecast

Line No.	Account	May, 2013 Actual	Budget	Actual Vs. Budget	Percentage Variation Actual vs. Budget	Line No.
	[A]	[B]	[C]	[D]	[E]	
1	Operating Revenues	$ 10,604,000	$ 9,931,000	$ 673,000	6.8%	1
2	Operating Expenses:					2
3	Cost Of Gas	4,469,000	3,912,000	557,000	14.2%	3
4	Other Operation and Maintenance	3,896,000	4,223,000	(327,000)	(7.7%)	4
5	Depreciation Expense	868,000	901,000	(33,000)	(3.7%)	5
6	Amortization Of Other Limited Term Gas Plant	-	-	-	-	6
7	Taxes Other Than Income	269,000	245,000	24,000	9.8%	7
8	Federal Income Taxes - Current	(587,000)	(451,000)	(136,000)	30.2%	8
9	State Income Taxes - Current	(222,000)	(99,000)	(123,000)	124.2%	9
10	Deferred Income Taxes	1,128,000	670,000	458,000	68.4%	10
11	Investment Tax Credit	-	-	-	-	11
12	Total Operating Expenses	9,821,000	9,401,000	420,000	4.5%	12
13	Operating Income	783,000	530,000	253,000	47.7%	13
14	Income From Utility Plant Leased to Others	-	-	-	-	14
15	Utility Operating Income	783,000	530,000	253,000	47.7%	15
16	Other Income, Net of Income Deductions	(13,000)	11,000	(24,000)	(218.2%)	16
17	Income Before Interest Charges	770,000	541,000	229,000	42.3%	17
18	Interest Charges	325,000	356,000	(31,000)	(8.7%)	18
19	Net Income	$ 445,000	$ 185,000	$ 260,000	140.5%	19

North Shore Gas Company

Comparison of Actual Financial Results to
the Originally Approved Forecast

Line No.	Account	June, 2013 Actual	Budget	Actual Vs. Budget	Percentage Variation Actual vs. Budget	Line No.
	[A]	[B]	[C]	[D]	[E]	
1	Operating Revenues	$ 9,400,000	$ 8,057,000	$ 1,343,000	16.7%	1
2	Operating Expenses:					2
3	Cost Of Gas	3,805,000	2,652,000	1,153,000	43.5%	3
4	Other Operation and Maintenance	3,901,000	4,441,000	(540,000)	(12.2%)	4
5	Depreciation Expense	870,000	905,000	(35,000)	(3.9%)	5
6	Amortization Of Other Limited Term Gas Plant	-	-	-	-	6
7	Taxes Other Than Income	239,000	249,000	(10,000)	(4.0%)	7
8	Federal Income Taxes - Current	(5,000)	(741,000)	736,000	(99.3%)	8
9	State Income Taxes - Current	(149,000)	(151,000)	2,000	(1.3%)	9
10	Deferred Income Taxes	120,000	670,000	(550,000)	(82.1%)	10
11	Investment Tax Credit	-	-	-	-	11
12	Total Operating Expenses	8,781,000	8,025,000	756,000	9.4%	12
13	Operating Income	619,000	32,000	587,000	1834.4%	13
14	Income From Utility Plant Leased to Others	-	-	-	-	14
15	Utility Operating Income	619,000	32,000	587,000	1834.4%	15
16	Other Income, Net of Income Deductions	(22,000)	15,000	(37,000)	(246.7%)	16
17	Income Before Interest Charges	597,000	47,000	550,000	1170.2%	17
18	Interest Charges	321,000	352,000	(31,000)	(8.8%)	18
19	Net Income	$ 276,000	$ (305,000)	$ 581,000	(190.5%)	19

North Shore Gas Company

Comparison of Actual Financial Results to
the Originally Approved Forecast

Line No.	Account	July, 2013 Actual	Budget	Actual Vs. Budget	Percentage Variation Actual vs. Budget	Line No.
	[A]	[B]	[C]	[D]	[E]	
1	Operating Revenues	$ 9,390,000	$ 8,676,000	$ 714,000	8.2%	1
2	Operating Expenses:					2
3	Cost Of Gas	3,714,000	2,716,000	998,000	36.7%	3
4	Other Operation and Maintenance	3,923,000	4,199,000	(276,000)	(6.6%)	4
5	Depreciation Expense	876,000	910,000	(34,000)	(3.7%)	5
6	Amortization Of Other Limited Term Gas Plant	-	-	-	-	6
7	Taxes Other Than Income	249,000	249,000	-	0.0%	7
8	Federal Income Taxes - Current	165,000	(467,000)	632,000	(135.3%)	8
9	State Income Taxes - Current	(19,000)	(102,000)	83,000	(81.4%)	9
10	Deferred Income Taxes	(24,000)	670,000	(694,000)	(103.6%)	10
11	Investment Tax Credit	-	-	-	-	11
12	Total Operating Expenses	8,884,000	8,175,000	709,000	8.7%	12
13	Operating Income	506,000	501,000	5,000	1.0%	13
14	Income From Utility Plant Leased to Others	-	-	-	-	14
15	Utility Operating Income	506,000	501,000	5,000	1.0%	15
16	Other Income, Net of Income Deductions	19,000	19,000	-	0.0%	16
17	Income Before Interest Charges	525,000	520,000	5,000	1.0%	17
18	Interest Charges	325,000	354,000	(29,000)	(8.2%)	18
19	Net Income	$ 200,000	$ 166,000	$ 34,000	20.5%	19

North Shore Gas Company

Comparison of Actual Financial Results to
the Originally Approved Forecast

Line No.	Account	August, 2013 Actual	Budget	Actual Vs. Budget	Percentage Variation Actual vs. Budget	Line No.
	[A]	[B]	[C]	[D]	[E]	
1	Operating Revenues	$ 8,708,000	$ 8,121,000	$ 587,000	7.2%	1
2	Operating Expenses:					2
3	Cost Of Gas	3,113,000	2,359,000	754,000	32.0%	3
4	Other Operation and Maintenance	3,714,000	4,039,000	(325,000)	(8.0%)	4
5	Depreciation Expense	878,000	915,000	(37,000)	(4.0%)	5
6	Amortization Of Other Limited Term Gas Plant	-	-	-	-	6
7	Taxes Other Than Income	241,000	245,000	(4,000)	(1.6%)	7
8	Federal Income Taxes - Current	65,000	(481,000)	546,000	(113.5%)	8
9	State Income Taxes - Current	(49,000)	(105,000)	56,000	(53.3%)	9
10	Deferred Income Taxes	160,000	670,000	(510,000)	(76.1%)	10
11	Investment Tax Credit	-	-	-	-	11
12	Total Operating Expenses	8,122,000	7,642,000	480,000	6.3%	12
13	Operating Income	586,000	479,000	107,000	22.3%	13
14	Income From Utility Plant Leased to Others	-	-	-	-	14
15	Utility Operating Income	586,000	479,000	107,000	22.3%	15
16	Other Income, Net of Income Deductions	(1,000)	23,000	(24,000)	(104.3%)	16
17	Income Before Interest Charges	585,000	502,000	83,000	16.5%	17
18	Interest Charges	326,000	357,000	(31,000)	(8.7%)	18
19	Net Income	$ 259,000	$ 145,000	$ 114,000	78.6%	19

North Shore Gas Company

Comparison of Actual Financial Results to the Originally Approved Forecast

Line No.	Account	September, 2013 Actual	Budget	Actual Vs. Budget	Percentage Variation Actual vs. Budget	Line No.
	[A]	[B]	[C]	[D]	[E]	
1	Operating Revenues	$ 8,486,000	$ 8,467,000	$ 19,000	0.2%	1
2	Operating Expenses:					2
3	Cost Of Gas	2,788,000	2,728,000	60,000	2.2%	3
4	Other Operation and Maintenance	4,315,000	4,466,000	(151,000)	(3.4%)	4
5	Depreciation Expense	885,000	924,000	(39,000)	(4.2%)	5
6	Amortization Of Other Limited Term Gas Plant	-	-	-	-	6
7	Taxes Other Than Income	234,000	244,000	(10,000)	(4.1%)	7
8	Federal Income Taxes - Current	(742,000)	(642,000)	(100,000)	15.6%	8
9	State Income Taxes - Current	(172,000)	(133,000)	(39,000)	29.3%	9
10	Deferred Income Taxes	514,000	670,000	(156,000)	(23.3%)	10
11	Investment Tax Credit	-	-	-	-	11
12	Total Operating Expenses	7,822,000	8,257,000	(435,000)	(5.3%)	12
13	Operating Income	664,000	210,000	454,000	216.2%	13
14	Income From Utility Plant Leased to Others	-	-	-	-	14
15	Utility Operating Income	664,000	210,000	454,000	216.2%	15
16	Other Income, Net of Income Deductions	3,000	27,000	(24,000)	(88.9%)	16
17	Income Before Interest Charges	667,000	237,000	430,000	181.4%	17
18	Interest Charges	321,000	362,000	(41,000)	(11.3%)	18
19	Net Income	$ 346,000	$ (125,000)	$ 471,000	(376.8%)	19

North Shore Gas Company

Comparison of Actual Financial Results to
the Originally Approved Forecast

Line No.	Account	October, 2013 Actual	Budget	Actual Vs. Budget	Percentage Variation Actual vs. Budget	Line No.
	[A]	[B]	[C]	[D]	[E]	
1	Operating Revenues	[redacted]				1
2	Operating Expenses:					2
3	Cost Of Gas					3
4	Other Operation and Maintenance					4
5	Depreciation Expense					5
6	Amortization Of Other Limited Term Gas Plant					6
7	Taxes Other Than Income					7
8	Federal Income Taxes - Current					8
9	State Income Taxes - Current					9
10	Deferred Income Taxes					10
11	Investment Tax Credit					11
12	Total Operating Expenses					12
13	Operating Income					13
14	Income From Utility Plant Leased to Others					14
15	Utility Operating Income					15
16	Other Income, Net of Income Deductions					16
17	Income Before Interest Charges					17
18	Interest Charges					18
19	Net Income					19

North Shore Gas Company

Comparison of Actual Financial Results to the Originally Approved Forecast

Line No.	Account	November, 2013				Line No.
		Actual	Budget	Actual Vs. Budget	Percentage Variation Actual vs. Budget	
	[A]	[B]	[C]	[D]	[E]	
1	Operating Revenues	[redacted]				1
2	Operating Expenses:					2
3	Cost Of Gas					3
4	Other Operation and Maintenance					4
5	Depreciation Expense					5
6	Amortization Of Other Limited Term Gas Plant					6
7	Taxes Other Than Income					7
8	Federal Income Taxes - Current					8
9	State Income Taxes - Current					9
10	Deferred Income Taxes					10
11	Investment Tax Credit					11
12	Total Operating Expenses					12
13	Operating Income					13
14	Income From Utility Plant Leased to Others					14
15	Utility Operating Income					15
16	Other Income, Net of Income Deductions					16
17	Income Before Interest Charges					17
18	Interest Charges					18
19	Net Income					19

North Shore Gas Company

Income Statement

Line No.	Description [A]	Test Year Ending December 31, 2015 [B]	Forecasted Year Ending December 31, 2014 (1) [C]	Forecasted Year Ending December 31, 2013 (2) [D]	Historical Year Ended December 31, 2012 (E)	Line No.
1	OPERATING REVENUES	$ 205,985,000	$ 207,124,000	$ 198,285,000	$ 162,358,000	1
2	OPERATING EXPENSES					2
3	Cost Of Gas	104,928,000	104,483,000	105,246,000	83,575,000	3
4	Other Operation and Maintenance	69,673,000	71,923,000	58,127,000	47,964,000	4
5	Depreciation Expense	11,759,000	11,028,000	10,517,000	9,908,000	5
6	Amortization Of Other Limited Term Gas Plant	-	-	-	-	6
7	Taxes Other Than Income	3,255,000	3,183,000	3,067,000	3,016,000	7
8	Income Taxes					8
9	Federal Income Taxes-Current	7,212,000	(4,264,000)	1,998,000	(3,282,000)	9
10	State Income Taxes-Current	538,000	474,000	(1,190,000)	(557,000)	10
11	Deferred Income Taxes	(2,928,000)	8,983,000	5,766,000	9,655,000	11
12	Investment Tax Credit	-	7,000	4,000	(27,000)	12
13	Total Operating Expenses	194,437,000	195,817,000	183,535,000	150,252,000	13
14	OPERATING INCOME	11,548,000	11,307,000	14,750,000	12,106,000	14
15	INCOME FROM GAS PLANT LEASED TO OTHERS					15
16	Revenues From Gas Plant Leased To Others	-	-	-	-	16
17	Expenses From Gas Plant Leased To Others	-	-	-	-	17
18	Total Income from Gas Plant Leased to Others	-	-	-	-	18
19	UTILITY OPERATING INCOME	11,548,000	11,307,000	14,750,000	12,106,000	19
20	OTHER INCOME AND (INCOME DEDUCTIONS)					20
21	Other Income					21
22	Interest and Dividend Income	262,000	602,000	129,000	(81,000)	22
23	Gain on Disposition of Property	-	-	-	-	23
24	Equity Earnings of Subsidiary Companies	-	-	-	-	24
25	Other	64,000	52,000	29,000	82,000	25
26	Total Other Income	326,000	654,000	158,000	1,000	26
27	Other Income Deductions	(208,000)	(207,000)	(188,000)	(130,000)	27
28	Taxes Applicable to Other Income and Deductions	(73,000)	(211,000)	(5,000)	67,000	28
29	Net Other Income and Income Deductions	45,000	236,000	(35,000)	(62,000)	29
30	INCOME BEFORE INTEREST CHARGES	11,593,000	11,543,000	14,715,000	12,044,000	30
31	INTEREST CHARGES					31
32	Interest on Long Term Debt	3,099,000	3,099,000	3,382,000	3,376,000	32
33	Amortization of Debt Discount and Expense	29,000	30,000	77,000	137,000	33
34	Amortization of Loss on Reacquired Debt	170,000	170,000	170,000	156,000	34
35	Other Interest	410,000	219,000	179,000	116,000	35
36	Total Interest Charges	3,708,000	3,518,000	3,808,000	3,785,000	36
37	NET INCOME	$ 7,885,000	$ 8,025,000	$ 10,907,000	$ 8,259,000	37

Notes: (1) Includes zero months of actual data and twelve months of forecasted data.
(2) Includes six months of actual data and six months of forecasted data.

North Shore Gas Company

Comparative Balance Sheets

Line No.	Description	Test Year Ending December 31, 2015	Forecasted Year Ending December 31, 2014 (1)	Forecasted Year Ending December 31, 2013 (2)	Historical Year Ended December 31, 2012	Line No.
	[A]	[B]	[C]	[D]	[E]	
1	**Assets**					1
2	Utility Plant, Net	$ 311,470,000	$ 295,006,000	$ 276,103,000	$ 263,636,000	2
3	Investment in Subsidiary Companies	-	-	-	-	3
4	Other Property and Investments	-	-	-	-	4
5	Current Assets	46,042,000	45,788,000	45,915,000	46,058,000	5
6	Other Assets	84,792,000	97,384,000	115,902,000	127,244,000	6
7	Total Assets	$ 442,304,000	$ 438,178,000	$ 437,920,000	$ 436,938,000	7
8	**Capitalization and Liabilities**					8
9	Proprietary Capital	$ 101,782,000	$ 93,838,000	$ 104,756,000	$ 93,839,000	9
10	Long Term Debt	82,000,000	82,000,000	82,000,000	74,499,000	10
11	Current Liabilities	76,884,000	76,216,000	50,367,000	60,626,000	11
12	Deferred Credits and Other Liabilities	181,638,000	186,124,000	200,797,000	207,974,000	12
13	Total Capitalization and Liabilities	$ 442,304,000	$ 438,178,000	$ 437,920,000	$ 436,938,000	13

Note: (1) Includes zero months of actual data and twelve months of forecasted data.
(2) Includes six months of actual data and six months of forecasted data.

North Shore Gas Company

Statement of Cash Flows

Line No.	Description	Test Year Ending December 31, 2015	Forecasted Year Ending December 31, 2014 (1)	Forecasted Year Ending December 31, 2013 (2)	Historical Year Ended December 31, 2012	Line No.
	[A]	[B]	[C]	[D]	[E]	
1	**Net Income**	$ 7,885,000	$ 8,025,000	$ 10,907,000	$ 8,259,000	1
2	**Adjustments to Reconcile Net Income to Net Cash**					2
3	**Flow Provided from Operating Activities:**					3
4	Depreciation and Amortization	11,759,000	11,028,000	10,517,000	9,908,000	4
5	Deferred Income Taxes and Investment Tax Credits, net	(2,920,000)	9,048,000	5,721,000	9,619,000	5
6	Pension (income)/ Post Retirement Liability	3,690,000	3,651,000	4,029,000	3,258,000	6
7	Pension and Post Retirement Funding	(4,797,000)	(6,139,000)	(3,377,000)	(10,902,000)	7
8	Other Changes	3,546,000	3,167,000	5,610,000	3,226,000	8
9	Changes in Working Capital, net	6,266,000	1,198,000	(14,009,000)	(3,725,000)	9
10	Net Cash Flow (used for) provided from Operating Activities	25,429,000	29,978,000	19,398,000	19,643,000	10
11	**Investing Activities**					11
12	Capital Expenditures	(28,067,000)	(30,075,000)	(24,379,000)	(21,438,000)	12
13	Other Investing Activities, net	-	-	(513,000)	212,000	13
14	Net Cash Flow used for Investing Activities	(28,067,000)	(30,075,000)	(24,892,000)	(21,226,000)	14
15	**Financing Activities**					15
16	Issuance of Long-Term Debt	-	-	54,000,000	28,000,000	16
17	Redemption of Long-Term Debt	-	-	(46,500,000)	(28,150,000)	17
18	Intercompany Loan Payable	2,638,000	19,097,000	(1,967,000)	11,900,000	18
19	Equity Contribution from Parent	-	-	-	-	19
20	Return of Capital Paid to Parent	-	-	-	-	20
21	Other Financing Activity, net	-	-	(314,000)	(234,000)	21
22	Dividends Paid to Parent	-	(19,000,000)	-	(10,000,000)	22
23	Net Cash Flow provided from (used for) Financing Activities	2,638,000	97,000	5,219,000	1,516,000	23
24	**Net Increase (Decrease) in Cash**	$ -	$ -	$ (275,000)	$ (67,000)	24

Note: (1) Includes zero months actual data and twelve months of forecasted data.
(2) Includes six months actual data and six months of forecasted data.

North Shore Gas Company

Statement of Retained Earnings (1)

Line No.	Description	Historical Year Ended December 31, 2012	Forecasted Year Ending December 31, 2013 (2)	Forecasted Year Ending December 31, 2014 (3)	Test Year Ending December 31, 2015	Line No.
	[A]	[B]	[C]	[D]	(E)	
1	Balance at Beginning of Period	$ 70,697,000	$ 68,955,000	$ 79,853,000	$ 68,878,000	1
2	Add:					2
3	Net Income	8,259,000	10,907,000	8,025,000	7,885,000	3
4	Other	-	-	-	-	4
5	Less:					5
6	Common Stock Dividends Declared	10,000,000	-	19,000,000	-	6
7	Other	1,000	9,000	-	-	7
8	Balance at End of Period	$ 68,955,000	$ 79,853,000	$ 68,878,000	$ 76,763,000	8

Note: (1) Excludes Accumulated Other Comprehensive (Income) Loss of $9,000 ($13,000 less tax impact of $4,000) at 12/31/2012 and $0 at 12/31/2013, 12/31/2014 and 12/31/2015 respectively.

Total Comprehensive Income (Loss) is $8,281,000, $10,916,000, $8,025,000 and $7,885,000 for Calendar Years 2012, 2013, 2014 and 2015 respectively.

(2) Includes six months of actual data and six months of forecasted data.
(3) Includes zero months of actual data and twelve months of forecasted data.