STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

Docket No. DG 23-067

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty
Distribution Service Rate Case
Marginal Cost of Service and Rate Design

DIRECT TESTIMONY

OF

KENNETH A. SOSNICK

Black and Veatch Management Consulting, LLC

July 27, 2023

Liberty™

THIS PAGE INTENTIONALLY LEFT BLANK

TABLE OF CONTENTS

TITLE PAGE

LIST OF ATTACHMENTS iii
LIST OF TABLES iii
I. INTRODUCTION 1
II. MARGINAL COST OF SERVICE TESTIMONY 2
   A. Overview and Summary of the MCS 2
   B. MCS Methodology 4
      1. Capacity Related Marginal Costs 9
      2. Customer-Related Marginal Costs 13
      3. Loading and Adjustment Factors 16
      4. Levelized Marginal Costs 17
   C. MCS Results 18
III. RATE DESIGN 19
   A. Normalized and Calendarized Test Year Revenues 20
   B. Target Revenue By Class 23
   C. Rate Calculation 28
   D. Rate and Bill Impacts 32

LIST OF ATTACHMENTS

Attachment KAS-1	Resume of Kenneth A. Sosnick
Attachment KAS-2	Marginal Cost of Service Study
Attachment KAS-3	Rate Design

LIST OF TABLES

Table 1. Summary of MCS Analyses 5
Table 2. Marginal Costs of Customer-Related Plant Additions 14
Table 3. Weighted Customer-Related Marginal O&M Cost by Class 15

Table 4. Summary of Loading Factors 17
Table 5. Marginal Costs by Rate Class ($,000) 19
Table 6. Target Revenue Allocation Summary.. 25
Table 7. Target Revenue Allocation Percentage By Class 26
Table 8. Current Rate Differentials For G-41/G-44... 29

I. INTRODUCTION

Q. Please state your full name, business address, and position.

A. My name is Kenneth A. Sosnick. My business address is 11401 Lamar Ave., Overland Park, Kansas, 66221. I am employed by Black and Veatch Management Consulting, LLC as a Managing Director.

Q. Please describe your business and educational background.

A. I am an economic consultant with more than twenty years of experience regarding rate-making and regulatory issues involving state and federally regulated utilities, including eight years as an Energy Industry Analyst at the Federal Energy Regulatory Commission ("FERC") in the Office of Administrative Litigation. I hold a Bachelor of Science in Accounting from the Indiana University of Pennsylvania. A copy of my curriculum vitae is included as Attachment KAS-1.

Q. What is your responsibility in connection with this proceeding?

A. I am responsible for preparing the Marginal Cost Study ("MCS") for Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty ("Liberty EnergyNorth" or "the Company") and for designing proposed rates for each of the Company's customer classes.

Q. How is your testimony organized?

A. My testimony is organized into three sections. This section, Section I, includes introductory material and describes the scope of my testimony. Section II describes the MCS that I prepared and its results. Section III discusses the development of the proposed customer class revenue targets, the proposed rates for each class, and describes bill impacts.

II. MARGINAL COST OF SERVICE TESTIMONY

A. Overview and Summary of the MCS

Q. Please explain the concept of marginal costs and their applicability to natural gas utilities.

A. Marginal costs are defined as the change in total cost that results from increasing the output of a good or service by one unit. In the context of a gas utility, this means the added cost to serve one additional dekatherm ("dth") of demand or one additional customer. When a utility like Liberty EnergyNorth is required to serve new demand or a new customer, it incurs a number of costs, including the cost of new infrastructure, increased Operations and Maintenance ("O&M") expenses, and other increased administrative and operational costs. The MCS measures the degree to which each of those costs increases when an additional increment of demand or a new customer is added to the system. In addition to these costs, a utility would also need to procure gas supply to meet the needs of incremental demand or customers; however, for purposes of this proceeding, that cost is excluded from the MCS since Liberty EnergyNorth's gas supply costs are recovered through the Company's Cost of Gas mechanism.

Q. How are the results of the MCS used in the ratemaking process?

A. The MCS establishes the marginal cost of a new customer or new increment of demand for each of Liberty EnergyNorth's rate classes. Marginal costs are then translated into revenue requirements, which reflect the annual levelized costs of incurring the marginal costs, inclusive of capital returns, taxes, depreciation, and other factors that are typically accounted for in utility ratemaking; annual levelized costs are equivalent to the Company's revenue requirement for each marginal cost incurred. The annualized levelized costs can, in turn, be used to inform the allocation of the Company's revenue requirement, which is described in the testimony of Company witness C. Drew Cayton, to establish rates for each rate class. I discuss the development of the Company's rates in Section III of my testimony.

Q. Please briefly explain the economic theory underlying marginal cost analysis and its applicability to utility ratemaking.

A. It is an established principle in economics that when prices for goods or services are equal to the marginal costs to provide those goods or services, consumers will make decisions about their consumption that tend to optimize the allocation of resources. Thus, using marginal costs to inform class revenue apportionment and rate design is an important part of the process to establish Liberty EnergyNorth's distribution rates. The Commission has recognized the appropriateness of using marginal costs for purposes of utility ratemaking in numerous proceedings, including the Company's distribution case in Docket No. DG 20-105. In addition to marginal costs, considerations are also given to rate stability and gradualism in the rate design process as will be discussed in Section III of this testimony

B. MCS Methodology

Q. Please explain your approach to conducting the MCS.

A. In conducting the MCS, I used data provided by the Company and approaches and methods that are generally consistent with the MCS Liberty EnergyNorth filed in its most recent rate case, Docket No. DG 20-105. The study can be envisioned as being conducted in three parts. *First,* I analyzed the relationships between Liberty EnergyNorth's costs, its design day demand, and its customer count. Some of Liberty EnergyNorth's costs increase primarily as a function of new demand, which I have categorized as capacity-related expenses. Other costs increase primarily as a function of new customers, which I have categorized as customer-related expenses. I also calculated a number of "loading factors," which account for relatively small costs whose causal relationships to other cost drivers are difficult to determine statistically. The results of these analyses indicate the initial marginal costs that Liberty EnergyNorth would incur to serve incremental demand and/or new customers. *Second,* I calculated Fixed Carrying Charge Rates ("FCCRs") to convert the initial marginal capital cost into the levelized, annual revenue requirement the Company would require for recovery of its initial investment. *Third*, I summarized my findings and estimated the total marginal costs per dekatherm of peak day demand and per customer for each of the Company's rate classes.

Table 1 below identifies each category of marginal costs that I analyzed and identifies the attachment to my testimony associated with each aspect of my analysis.

Table 1. Summary of MCS Analyses

Item	Marginal Cost Category	Attachment
	Capacity-Related Marginal Costs	
1	Addition of production plant used in lieu of mains reinforcement	KAS-2 -MCOS-1
2	Costs of mains reinforcements to meet incremental demand	KAS 2 -MCOS-2
3	Costs of mains extensions to meet incremental demand	KAS-2 -MCOS-2
4	Costs of distribution O&M to meet incremental demand	KAS-2 -MCOS-2
5	Costs of production O&M to meet incremental demand	KAS-2 -MCOS-2
	Customer-Related Marginal Costs	
6	Costs to new plant additions (meters and services) to serve incremental customers	KAS-2-MCOS-3
7	Costs of O&M to serve incremental customers	KAS-2-MCOS-3
8	Costs of Accounting and Marketing to serve incremental customers	KAS-2-MCOS-3
	Loading and Adjustment Factors	
9	Plant-related Administrative and General (“A&G”) loading factor	KAS-2-MCOS-4
10	Non-plant-related A&G loading factor	KAS-2-MCOS-4
11	M&S (materials and supplies) and prepayments loading factor	KAS-2-MCOS-4
12	General plant loading factor	KAS-2-MCOS-4
13	Bad debt expense adjustment factor	KAS-2-MCOS-4
	Levelized Annual Marginal Costs	KAS-2-MCOS-5
Summary of Results		KAS-2-MCOS-6

Q. Please summarize the method you used to estimate the capacity- and customer-related marginal costs shown above.

A. My estimate of the marginal cost to add production plant in lieu of mains reinforcement, listed above as Item 1, is based on an analysis of engineering data provided by the Company, as I explain in detail later in my testimony. To estimate the marginal costs associated with Items 2 through 8, I first conducted regression analyses using data the Company provided. If the resulting regression equations that I estimated to parameterize the driver of each cost category was sufficiently robust, the slope value was used to estimate the marginal cost. If it was not, I based the marginal cost for each category on historical actual cost rates, as I explain in more detail below.

Q. Please explain the general approach that you used in conducting the regression analyses.

A. The Company provided annual cost data for the period 1989 to present for each of the cost categories listed as Items 2–8 in Table 1. I adjusted expense data using a general inflation index and adjusted the plant cost data using the most recent version of the Handy Whitman Index.[1] Liberty EnergyNorth also provided peak design day demand and annual customer counts for the same period. For each of the capacity-related marginal costs (Items 2–5 above),[2] I regressed the cost items against peak design day consumption. For each of the customer-related marginal costs (Items 6–8), I regressed the cost items against annual customer count. Among the results produced is a coefficient that indicates the slope of the regression line found to be the best fit for the data. The coefficient indicates the rate at which the cost variable would increase for every unit change in the independent variable, either demand for gas, in which case the

[1] The Handy Whitman Index calculates cost trends for specific sectors, which allows for the estimation of industry-specific inflation calculations. To develop the calculations described in my testimony I used the January 2023 Handy-Whitman Table G-1 (Cost Trends of Gas Utility Construction, North Atlantic Region).

[2] Regression was used for a portion of the costs for item 2 (Main reinforcements). The other portion was based on estimated incremental costs per incremental changes in dekatherms provided by the Company.

rate of change in costs is expressed on a \$/peak design day dth basis, or customer count, in which case the rate of change is expressed on a \$/customer basis.

More formally, the regression equations can be summarized as follows:

$$\textit{Cost Variable} = a + b * \textit{Cost Driver Variable}$$

where the *Cost Variable* is the cost data provided by the Company for each category identified in Items 2–8 in Table 1. The *Cost Driver Variable* is the Company data for either design day demand (for capacity-related marginal costs) or customer count (for customer-related marginal costs). *a* is the y-axis intercept of a line that is fit to the data available using regression analysis; that intercept is often referred to as being defined by the regression line. *b* is the coefficient that represents the slope of the regression line, which is the rate at which the *Cost Variable* increases with each unit of the *Cost Driver Variable*; thus, for purposes of the MCS, *b* indicates the unit marginal cost for each of the cost categories shown above for which I was able to estimate a sufficiently robust relationship using linear regression.

Q. Is regression analysis a widely accepted method for conducting marginal cost studies?

A. Yes, the general method I have adopted is widely accepted. Regression analysis is widely used in New Hampshire rate proceedings and elsewhere for marginal cost studies for gas and electric utilities, including in the Company's most recent distribution rate case before the Commission. Additionally, the use of historical cost rates in instances in which a sufficiently robust relationship between cost and driver variables cannot be found using regression is also common practice in New Hampshire and other jurisdictions.

Q. How did you determine which of the regressions satisfactorily capture the relationship between the cost and driver variables?

A. There were three primary criteria I utilized to confirm that the regression equations I have identified adequately capture the relationship between the cost variable and the cost driver variable. *First*, I reviewed the R-squared statistic, which is sometimes referred to as the coefficient of determination. R-squared is the square of the coefficient of correlation between the *Cost Variable* and the *Cost Driver Variable* and is a statistical measure of how closely the data fit the regression line. *Second*, I confirmed that each of the regression coefficients – the *b* or slope variables – had the "correct" sign. In this case, that means that all of the coefficients should be positive. *Third*, I reviewed the t-statistic and p-value for each regression, both of which are measures of the explanatory power of the *b* coefficient.

Q. Did you reject any regressions?

A. Yes, I did. In several instances I rejected the results of the regression analysis because the equation indicated a coefficient with the incorrect (negative) sign, a low R-squared, or both. As I describe in detail below, in each of those instances I based my estimate of the marginal cost for that cost category on cost rates that I calculated using historical data provided by the Company.

1. Capacity Related Marginal Costs

Q. Please summarize the capacity-related marginal costs that you estimated using regression analysis.

A. I estimated five types of marginal costs that the Company would incur for each additional increment of design day demand, each of which are listed in Table 1: (Item 1) marginal costs associated with the addition of new production plant that the Company could install in lieu of reinforcing its network of distribution mains; (Item 2) marginal costs of investing in mains-related system reinforcements to meet incremental demand; (Item 3) marginal costs of extending mains to serve incremental demand; (Item 4) marginal distribution O&M costs associated with serving each increment of new demand; and (Item 5) marginal production O&M costs associated with serving each increment of new demand.

Q. How did you estimate Item 1, the marginal cost of new production in lieu of mains reinforcement to serve incremental demand?

A. Liberty EnergyNorth owns Liquid Propane ("LP") and Liquefied Natural Gas ("LNG") facilities in its service territory, which it uses to maintain pressure when its system is at or near peak demand conditions. I asked the Company to develop an estimate of the costs of hypothetical additions to expand the capacity at its LP and LNG facilities and determine how much of that new capacity would be used to maintain system pressure. The Company determined the best cost estimate for new production facilities is the 2021 cost estimate associated with the Keene facility conversion. The 2021 estimate indicated a cost estimate of $7,361,103 for an incremental capacity of 9,600 dth. The Company determined that 8.73% of that capacity would be used to maintain pressure during peak conditions. I increased the capital expense amount by approximately 11.4% to account for two years of inflation between 2021 and 2023, which I determined by reviewing the U.S. Bureau of Economic Analysis's Gross Domestic Product Implicit Deflator most recently published in February 2023.[3] The result is a marginal unit cost estimate for production plant of $854.41/dth of incremental design day demand. As stated previously, the percentage related to pressure support is 8.73%. Thus, the unit cost of the production plant for the distribution function is $74.62/dth ($854.41 x 8.73%). My calculations are shown in Schedule MCOS-1.

Q. How did you estimate Item 2, the marginal cost of mains-related reinforcement to serve incremental demand?

A. Mains-related reinforcement costs are the costs that the Company incurs for reinforcing its system to maintain operations to meet incremental demand. I asked the Company to prepare an engineering study that forecasted system reinforcement projects that Liberty EnergyNorth expects to install over the period 2023 to 2033 in response to growing demand and the expected costs of those projects. The list of projects provided for system enhancement, gas system planning, and reliability included both mains (93%) and other projects (7%) related to gate stations and meter and regulator stations. Since all of these projects relate to system reinforcement, I have included them in the analysis. For the system enhancement projects the Company also provided an estimate of the additional

[3] https://fred.stlouisfed.org/series/A191RD3A086NBEA.

dekatherms that will be supported by those projects. I therefore divided the total costs ($51.32 million) between 2023 and 2033[4] by the increase in dekatherms (40,000) to yield a marginal cost of $1,283 /dth. For the gas system planning and reliability projects I developed a regression analysis to estimate the statistical relationship between the cost of those reinforcement costs and the forecasted design day demand through 2033. As shown in Schedule MCOS-2 at page 1, I found the marginal cost of the system planning and reliability portion of mains reinforcement to be $4,205/dth of incremental design day demand. When both reinforcement components are added together the cost for main reinforcements is $5,488/dth.

Q. How did you estimate Item 3, the marginal cost of mains extensions to meet serve incremental demand?

A. The marginal cost for mains extension is the cost that Liberty EnergyNorth will incur to extend its network for each dth by which design day demand grows. The Company provided me with data for the period 1989–2019 that included the costs of new mains extensions and design day demand for each year. Using this data, I conducted regression analysis to estimate the relationship between design day demand and the cumulative new main extensions and determined that the marginal cost of mains extensions is approximately $1,621/dth of incremental design day demand, as shown in Schedule MCOS-2 at page 2.

[4] The Company's forecast currently includes zero dollars for 2029 – 2033.

Q. How did you estimate Item 4, the marginal cost of distribution O&M to serve incremental demand?

A. The Company provided me with data for O&M related to distribution operations for the period 1989–2019. I conducted regression analysis to estimate the relationship between those cost data and design day demand, which indicated that the Company's marginal cost of distribution O&M is $61.69/dth of incremental design day demand, as shown in Schedule MCOS-2 at page 3.

Q. How did you estimate Item 5, the marginal cost of production O&M to serve incremental demand?

A. Production O&M costs are those costs that Liberty EnergyNorth incurs for the operation and maintenance of its LNG and LP facilities. To estimate that cost, I first ran a regression to determine the relationship between design day demand and total production related expenses using data provided by the Company. However, the resulting equation had a sign that was barely above zero and a very low R^2. I therefore rejected it and instead estimated the marginal cost using Liberty EnergyNorth's historical average production cost, which I determined to be $9.79/dth of incremental design day demand. Because that estimate is total production cost, it must be allocated to the distribution function since the objective is to determine the marginal cost of pressure support. To do so, I utilized the same rate, 8.73%, that was used to allocate the cost of new production in lieu of mains to the pressure support function. The resulting estimate of the marginal cost for production O&M is $0.85/dth of incremental design day demand, as shown in Schedule MCOS-2 at page 4.

2. Customer-Related Marginal Costs

Q. Please explain the concept of customer-driven marginal costs.

A. For some cost categories, the Company's costs are driven more by the number of its customers than by customers' total consumption. For example, Liberty EnergyNorth's cost of meters is driven entirely by its customer count – a meter must be installed for each new customer regardless of consumption. For each of the customer-driven cost categories, the marginal cost is equal to the Company's additional cost in that category that results from a single new customer. Accordingly, each of the customer-driven marginal costs are expressed on a $/customer basis.

Q. Please summarize the customer-related marginal costs that you estimated.

A. I estimated three types of marginal costs that the Company would incur for each new customer: (Item 6 from Table 1) the costs of new meter and services plant additions for each incremental customer; (Item 7) O&M costs associated the new plant additions for each incremental customer; and (Item 8) Accounting and Marketing costs the Company will incur for each new customer.

Q. How did you estimate Item 6, the marginal cost of plant additions to serve incremental customers?

A. Customer-driven marginal costs of plant additions are the costs of installing a meter and service for new customers. The Company provided me with its current costs by rate class, which are shown below. Additional detail is provided in Schedule MCOS-3 at page 1:

Table 2. Marginal Costs of Customer-Related Plant Additions

	R-1	R3, R-4	G-41	G-42	G-43	G-51	G-52	G-53	G-54
Service	$5,250	$5,250	$5,576	$8,072	$5,027	$5,576	$8,072	$5,027	$5,027
Meter	$732	$732	$1,805	$4,060	$9,858	$1,805	$4,060	$9,858	$9,858
Total	$5,982	$5,982	$7,381	$12,132	$14,885	$7,381	$12,132	$14,885	$14,885

Q. How did you estimate Item 7, the marginal cost of O&M to serve incremental customers?

A. Customer-related O&M expense is the expense that the Company incurs to operate and maintain its meters and services; as such, it is separate from the Company's distribution O&M discussed above. To estimate the marginal cost of customer-related O&M, I first developed regressions based on historical data for customer-related O&M and annual customer count the Company provided. Customer-related O&M for each year was restated to 2022 dollars using the GDP implicit price deflator mentioned previously. Because the resulting regression equation had an incorrect sign and a low R-squared, I rejected it and instead based my estimate of the marginal cost on an average O&M cost per customer, taking into consideration the trend in the costs over time. Over approximately the first sixteen years, these costs steadily declined and have been followed by periods of highs and lows. I ultimately used a 10-year average cost which is $69.99/customer, as shown at page 2 of Schedule MCOS-3. Because customer-related O&M is likely to vary by rate class, I conducted additional analysis to weight the marginal costs for each class based on the contribution to total costs of each class, as shown at page 3 of Schedule MCOS-3. The resulting marginal costs for O&M to serve incremental customers for each rate class is shown below:

Table 3. Weighted Customer-Related Marginal O&M Cost by Class

Class	Class weighted marginal cost per customer
R1	$64.94
R-3, R-4	$64.94
G-41	$80.13
G-42	$131.70
G-43	$161.58
G-51	$80.13
G-52	$131.70
G-53	$161.58
G-54	$161.58

Q. How did you estimate Item 8, marginal Accounting and Marketing costs to serve incremental customers?

A. The Company provided historical data for accounting and marketing expenses for the period 1989 to present. I prepared a regression analysis to determine the statistical relationship between those expenses and annual customer count. Because that analysis showed a negative slope between customer count and accounting and marketing expense, I chose to base my estimate of the marginal cost on average cost. The average cost steadily declined for the first thirteen years and was followed by a steady increase over the next ten years and then a general decline over the most recent eight years. Given these trends, I chose a five-year average that results in a cost of that category of $43.85/customer. My calculations are shown at page 4 of Schedule MCOS-3.

3. Loading and Adjustment Factors

Q. Please identify the loading factors you estimated.

A. The loading factors I calculate are for (a) plant-related A&G expense, (b) non-plant-related A&G expense, (c) M&S and prepayments, and (d) general plant.

Q. What is the relevance of the loading factors to the MCS?

A. Each of the loading factors define relatively small costs that the Company will incur as a result of increasing demand and/or customer count that should be included in its marginal cost but that are difficult to estimate directly using the statistical approaches described above. I therefore based my estimates of the loading factors on the historical relationship between these cost categories and other costs from data that was provided by the Company. For example, I compiled the Company's total utility plant cost and its plant-related A&G expense for each year for the period 1989 through the present and determined that, on average, plant-related A&G expense was approximately 0.18% of the total utility plant cost. I conducted similar analyses for each of the other loading factors, in the completion of which I compared non-plant A&G expense to adjusted O&M, materials & supplies and prepayments to total utility plant, and general plant to total utility plant. In each of these analyses I took into consideration the trends in the factors over time. My calculations are provided at pages 1–4 of Schedule MCOS-4 and are summarized in Table 4, below:

Table 4. Summary of Loading Factors

Category	Loading Factor	Unit
Plant-related A&G expense	$0.0018	/$ of utility plant
Non-plant related A&G expense	$0.6282	/$ of adjusted O&M
M&S and prepayments	$0.0157	/$ of utility plant
General Plant	$0.0705	/$ of utility plant

Q. Did you calculate any other adjustment factors?

A. Yes, using data provided by the Company, I calculated a percentage-based estimate of bad debt expense per customer class, as shown at page 5 of Schedule MCOS-4.

4. Levelized Marginal Costs

Q. Please explain the relevance of the levelized marginal costs.

A. Each of the marginal costs for investments in infrastructure described earlier in my testimony is the initial cost that will be incurred by the Company to place services, meters, and plant into service to serve new demand or customers. These costs must be converted into levelized, annual costs that include recovery of the Company's authorized return and other factors to establish marginal costs that reflect Liberty EnergyNorth's cost of service.

Q. How did you convert the initial marginal costs into levelized marginal costs?

A. I calculated FCCR for each type of investment that the Company would incur to meet new demand or to serve new customers – (a) production plant, (b) mains-reinforcements, (c) mains-extensions, (d) services, and (e) meters. For each, I calculated an Engineer's FCCR and an Economist's FCCR, which are the annual revenue requirements, expressed as a percentage of the initial capital investment, for each type of investment inclusive of the Company's required returns, taxes, depreciation, and other factors that are reflected in utility ratemaking for capital investment. The only difference between the two rates is that the Engineer's FCCR is expressed in nominal dollars while the Economist's FCCR is expressed in constant dollars that account for the value of inflation; the Present Value ("PV") of the income streams that underlie the FCCR calculations is the same for both. For purposes of marginal cost analyses, it is generally accepted that use of the Economist's FCCR is most appropriate and is consistent with the Company's most recent MCS in Docket No. DG 20-105. The inputs used to conduct the levelized cost analysis are shown at pages 1–2 of Schedule MCOS-5, the detailed calculation of the four FCCRs are shown at pages 3–7 of Schedule MCOS-5, and the Economist's and Engineer's FCCRs are shown at page 8 of Schedule MCOS-5.

C. MCS Results

Q. Please identify the schedules you have prepared to summarize the results of the Marginal Cost Study.

A. Schedule MCOS-6, page 1, shows the calculation of capacity-related marginal costs inclusive of loading factors and adjustments. Schedule MCOS-6, page 2, shows the calculation of customer-related marginal costs, including all loading factors and adjustments. Schedule MCOS-6, page 3, summarizes the cost estimates.

Q. Please summarize the results of the MCS.

A. The results of the MCS are summarized in Table 5, below.

Table 5. Marginal Costs by Rate Class ($,000)

Class	Customer - related	Capacity-related	Total	Share
R-1	$2,445	$408	$2,854	1.5%
R3, R-4	$57,907	$47,030	$104,937	55.5%
G-41	$8,262	$19,436	$27,698	14.7%
G-42	$2,020	$24,847	$26,867	14.2%
G-43	$114	$7,311	$7,425	3.9%
G-51	$1,103	$1,961	$3,064	1.6%
G-52	$566	$4,373	$4,939	2.6%
G-53	$61	$6,067	$6,128	3.2%
G-54	$47	$4,991	$5,039	2.7%

III. RATE DESIGN

Q. What is the purpose of this section of your testimony?

A. In this section of my testimony I describe the analysis I undertook to develop proposed rates for each of the Company's rate classes.

Q. How is this section of your testimony organized?

A. In this section of my testimony I describe the steps taken to develop proposed rates for Liberty EnergyNorth customers. The steps in this process and the order of items discussed in this section of testimony are shown below.

1. Develop calendar and weather normalized test year revenues at current rates.
2. Develop proposed target revenue by class.
3. Determine customer and volumetric target revenue by class.
4. Determine rate differentials and calculate proposed rates.
5. Evaluate customer bill impacts.

A. Normalized and Calendarized Test Year Revenues

Q. Were the revenues and sales volumes shown in RATES-2 adjusted for the rate design calculation?

A. Yes. Volumes and/or revenues were adjusted to normalize for weather and for calendar month accounting.

Q. Please explain the weather normalization adjustment.

A. It is generally accepted practice in New Hampshire and elsewhere to set rates using billing normalized determinants rather than actuals. Sales for a gas utility are sensitive to weather – generally speaking, the colder it is, the more gas the utility will sell. Thus, normalized sales and revenues are those that would likely have been realized during some period based on historical relationships between sales and weather, had the weather been normal for that period, holding all other factors constant. Normalizing the determinants allows the inputs to the rate analysis to better reflect the sales and revenues the Company would be likely to achieve in a normal year.

Q. How did the Company normalize the data for weather?

A. The sales data were normalized in the same manner as in Docket No. DG 20-105. The Company determined that in some winter months in the test year, sales were higher than normal due to variations in weather while in other months they were lower.

Q. Given that the Company has a revenue decoupling mechanism, is weather normalization necessary?

A. Yes. As I explain above, one of the objectives of the ratemaking process is to encourage consumers to make efficient decisions regarding their gas consumption, an objective that is supported by establishing rates that change in ways that are predictable and understandable. If the Company were to set rates based on a test year that did not reflect normal conditions, consumers' total cost of gas would change via an adjustment made in the decoupling mechanism, even if all other factors were held constant. The result could be confusing to customers and may distort the price signals that support their efficient consumption decisions. In Docket No. DG 17-048, the Commission recognized this fact and approved the Company's billing determinant weather normalization, concurrent with Liberty EnergyNorth's decoupling mechanism approval. Additionally, weather normalized billing determinants were used in the development of rates in the Company's last rate case, Docket No. DG 20-105.

Q. Please explain the calendar month adjustment.

A. The Company's billing cycles are not based on calendar months; however, it has chosen to recast its cycle-based, normalized revenues on a calendar basis because it consistent with generally accepted accounting principles and with the Company's past practices in proceedings before the Commission, and because calendar month data permits easier and simpler calculation of revenues in the event of rate changes since such changes occur at the start of a calendar month. The adjustment is calculated as the difference between actual therms billed each month and the calculated volumetric billing determinants for each month.

Q. What other adjustments were made to develop the billing determinants for the weather-normalized revenues?

A. For purposes of this initial testimony, MEP class billing determinants as well as the R-4 class were determined using a proration that is based on July 2021 – June 2022 billing determinants. The proration percentages were then applied to the January 2022 – December 2022 consolidated class billing determinants that are more readily available from the Company's SAP system. For example, the Company's "R-1" consolidated class is composed of R-1 and R-5 data. This consolidated class billing determinants were broken down into R-1 and R-5 using the proration developed from the more detailed billing determinants for July 2021 – June 2022.

Q. Will the Company update the billing determinants when the data becomes available?

A. Yes.

Q. Do you expect the billing determinants to materially change when the update is made?

A. No. The July 2021 – June 2022 billing data shows that the MEP and R-4 classes combined represent just 0.45% of total company bills and 0.49% of total company therms.

Q. Which base rates were used for the calculation of the weather-normalized revenues?

A. Delivery rates that will become effective August 1, 2023, were used as "current rates" for the development of test year weather-normalized revenues. Delivery rates effective August 1, 2023, will reflect the ending of a previous step change adjustment.

Q. When the August 1, 2023, delivery rates are applied to the calendar and weather normalized billing determinants, what is the resulting weather-normalized revenues?

A. I have calculated the test year weather-normalized revenues at current rates to be $96,553,144. This calculation is shown in Schedule RATES-2.

B. Target Revenue By Class

Q. Please briefly summarize your approach to the calculation of target revenue by class.

A. First, I identified the total company revenue requirement (total target revenue) from Mr. Cayton's functional cost of service testimony. Second, I determined the target revenue allocations between the Residential and Commercial & Industrial ("C&I") groups of classes. Third, I determined the intra residential and intra C&I allocations to each MEP/Non MEP class groupings; I also refer to these as MCOS class groupings. Fourth, I determined the customer versus volumetric target revenue allocations for each MCOS grouping.

Q. Can you summarize the target revenue allocations to each class?

A. Yes. The tables on the next page show the target revenue allocated to each MCOS class grouping as well as the allocations for the customer and volumetric rate components. This information is also shown in Schedule RATES-3 page 1.

Table 6. Target Revenue Allocation Summary

Class	Norm. TY Revs @ Stated Current Rates (Eff. 8/1/23)	Target Revenues @ Full MCOS	Proposed Class Target Revenue	Class Revenue Incr/(Decr)	Class Revenue % Increase	Customer Allocation	Volumetric Allocation	Customer Target Revenue	Volumetric (Energy) Target Revenue
Residential									
R-1/R-5	$1,053,354	$1,831,227	$1,343,811	$290,457	27.57%	55.5%	44.5%	$746,097	$597,714
R-3/R-4/R6/R-7	$52,353,807	$67,340,247	$66,790,091	$14,436,284	27.57%	25.7%	74.3%	$17,168,925	$49,621,166
Total Residential	$53,407,161	$69,171,474	$68,133,902	$14,726,741	27.57%			$17,915,022	$50,218,880
C&I									
G-41/G-44	$16,380,339	$17,774,399	$20,166,400	$3,786,061	23.11%	38.9%	61.1%	$7,842,842	$12,323,558
G-42/G-45	$15,647,893	$17,240,854	$19,264,660	$3,616,768	23.11%	18.7%	81.3%	$3,605,082	$15,659,578
G-43/G-46	$3,739,454	$4,764,591	$4,603,770	$864,317	23.11%	14.6%	85.4%	$672,788	$3,930,983
G-51/G-55	$1,871,369	$1,966,298	$2,303,906	$432,538	23.11%	45.7%	54.3%	$1,052,582	$1,251,324
G-52/G-56	$2,598,462	$3,169,215	$3,199,056	$600,594	23.11%	31.4%	68.6%	$1,005,551	$2,193,505
G-53/G-57	$1,767,887	$3,932,244	$2,176,506	$408,620	23.11%	17.0%	83.0%	$369,612	$1,806,895
G-54/G-58	$1,140,581	$3,233,335	$1,404,208	$263,628	23.11%	21.4%	78.6%	$300,566	$1,103,643
Total C&I	$43,145,983	$52,080,936	$53,118,508	$9,972,525	23.11%			$14,849,022	$38,269,486
Total Revenue	$96,553,144	$121,252,410	$121,252,410	$24,699,266	25.58%			$32,764,044	$88,488,366

Table 7. Target Revenue Allocation Percentage By Class

Class	Norm. TY Revs @ Stated Current Rates (Eff. 8/1/23)	Target Revenues @ Full MCOS	Proposed Class Target Revenue	Class Revenue Incr/(Decr)	Customer Target Revenue	Volumetric (Energy) Target Revenue
<u>Residential</u>						
R-1/R-5	1.09%	1.51%	1.11%	1.18%	2.28%	0.68%
R-3/R-4/R6/R-7	54.22%	55.54%	55.08%	58.45%	52.40%	56.08%
Total Residential	55.31%	57.05%	56.19%	59.62%	54.68%	56.75%
<u>C&I</u>						
G-41/G-44	16.97%	14.66%	16.63%	15.33%	23.94%	13.93%
G-42/G-45	16.21%	14.22%	15.89%	14.64%	11.00%	17.70%
G-43/G-46	3.87%	3.93%	3.80%	3.50%	2.05%	4.44%
G-51/G-55	1.94%	1.62%	1.90%	1.75%	3.21%	1.41%
G-52/G-56	2.69%	2.61%	2.64%	2.43%	3.07%	2.48%
G-53/G-57	1.83%	3.24%	1.80%	1.65%	1.13%	2.04%
G-54/G-58	1.18%	2.67%	1.16%	1.07%	0.92%	1.25%
Total C&I	44.69%	42.95%	43.81%	40.38%	45.32%	43.25%
Total Proportion	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Q. Please explain why certain classes are combined together for initial target revenue allocation.

A. MEP classes, which represent a very small portion of revenues, have rates that are directly tied mathematically to non-MEP rates. The classes are combined into their related groups. In addition, R-4 rates are directly tied with R-3 rates. As such, R-3, R-4, R-6 (MEP), and R-7 (MEP) are combined into one group. Once revenue targets are set for these groups, rates can be derived based on rate differentials chosen for each specific rate class. These differentials are discussed later in my testimony.

Q. Please explain the overall residential and C&I target revenue allocation.

A. Based on the MCOS the residential classes would be allocated 57.1% of total target revenues. Under normalized test year revenues at current rates, the residential classes would contribute 55.3% of total revenues. If the system average increase of 25.58% were to be applied to revenues for all classes, the residential class target revenue would have to be set at 97.0% of full MCOS. In an effort to move the residential (and C&I) classes toward full MCOS I set the residential target revenue at 98.5% of what it would be under a full MCOS allocation.

Q. Please explain the intra residential and intra C&I target revenue allocation.

A. In order to maintain consistency with current rates, I elected to use the intra residential and intra C&I allocations from the normalized test year revenues at current rates.

Q. How did you determine the customer and volumetric allocations for each class?

A. I initially reviewed the customer component allocation based on the MCOS. Even after using the allocations described above, the MCOS customer allocation percentages would have resulted in significant increases in the customer charge (as high as 142%) for the residential class and significant decreases for some of the C&I classes (as high as 95.2%). If the customer percentages from the normalized test year revenues at current rates are used, each class would see customer charge increases in the range of 23.1% to 27.6%. Given the already significant increase from the total system target revenue and its potential impact on the fixed portion of customer's bills, and to maintain consistency and stability, I have set the customer percentages for each class at 90% of the customer percentages from the normalized test year revenues. This method effectively reduces the customer charge rate increase for all classes by about half of what it would have been had the full customer percentage from normalized test year revenues been used.

C. Rate Calculation

Q. Please explain the process used for calculating the proposed rates once the target revenues are established.

A. The first step is to choose the rate differential for each group of rates. Using the assigned target revenues, billing determinants and chosen rate differentials, proposed rates can be calculated mathematically.

Q. Please explain what is meant by rate differentials.

A. For each MCOS class grouping and rate type there are multiple classes and rates. Some rates within a group differ because they are MEP rates (1.3 x the standard rate). Others differ based on the season or volumetric block (head bock or tail block). As such, rates within a group can be assigned a differential value. For example, if the current winter head block rate for G-41 was assigned as the base rate with a differential of "1," the other rates could be expressed as shown in the table below.

Table 8. Current Rate Differentials For G-41/G-44

Rate Type	G-41	G-44 MEP
Current Rate (Eff. 8/1/23)		
Energy-Summer-HB	$0.4928	$0.6407
Energy-Summer-TB	$0.3390	$0.4406
Energy-Winter-HB	$0.4928	$0.6407
Energy-Winter-TB	$0.3390	$0.4406
Rate Differential		
Energy-Summer-HB	1.00	1.30
Energy-Summer-TB	0.69	0.89
Energy-Winter-HB	1.00	1.30
Energy-Winter-TB	0.69	0.89

Q. What rate differentials did you use for proposed rates?

A. I used the same differentials that are represented in current rates. This method ensures that the required MEP differentials are maintained and helps maintain the current differences in rates between seasons and blocks.

Q. Please explain how the proposed rates were calculated once the differentials were chosen.

A. Mathematically the "base" rate with a differential of "1" can be calculated by dividing the target revenue for each MCOS group by the product of the rate differentials and their corresponding billing determinants. The steps in this process consisted of the following.

1. Calculate rates for all classes but assume R-4 and R-7 are not discounted, *i.e.*, R-4 equals the R-3 rate and the R-7 rate equals 1.3x the R-4 rate. (See lines 1-36 of Schedule RATES 4)
2. Perform a revenue check for all classes using the undiscounted rates above for R-4 and R-7. (See lines 37-52 of Schedule RATES 4)
3. Calculate discounted revenues by discounting the R-4 by the required 45%. R-7 is then calculated as 1.3x the now discounted R-4 rate.[5](See lines 53-105 of Schedule RATES 4)
4. Compare the revenues in step 2 to the revenues in step 3 to derive the revenue shortfall to be collected in the GAP ("Gas Assistance Program") component of the Local Distribution Adjustment Charge ("LDAC"). (See lines 105-107 of Schedule RATES 4)

---

[5] Rates are also rounded in this step. Customer charge is rounded to two decimals while volumetric charges are rounded to four decimals.

Q. What is the total revenue requirement that the Company's proposed distribution base rates are designed to recover?

A. The proposed rates (including discounted R-4 and R-7 rates) are designed to recover $119,635,219 as shown at Line 105 and 161 of Schedule RATES-4. The revenue shortfall from the discounted R-4 and R-7 rates is $1,620,206, as shown at Line 162 of Schedule RATES-4, which will be collected through the LDAC mechanism. These two revenue values sum to $121,255,425 which is within 0.002% of the $121,252,410 total delivery target revenue shown in Schedule RR-EN-2 in Mr. Culbertson and Mr. Cayton's revenue requirement testimony.

Q. Is your rate design approach generally consistent with the Company's previous practices before the Commission?

A. Yes. In its request for a rate increase in Docket No. DG 17-048, the Company initially requested an increase in rates for residential customers of more than 30% and much smaller increase for C&I customers (less than 20%), based largely on the results of the MCS it had developed for that proceeding. The rate design that was ultimately approved by the Commission in that proceeding resulted in average percentage increases to rates for the residential and C&I classes that were nearly identical. Similarly, in Docket No. DG 20-105, the system average increase was also applied to each class. As proposed by the Company in this case, the system average increase is not directly applied but the end result of the allocations described previously are relatively close to the system average increase.

Q. Have you prepared a proof of the revenues that the proposed rates produce?

A. Yes, I have. Schedule RATES-4 shows the calculation of the proposed rates and the calculation of revenues at each of the undiscounted and discounted rate steps described previously.

D. Rate and Bill Impacts

Q. Please summarize your proposed rates.

A. Table 9 shows the current and proposed customer charge for the Winter season for each class along with the change, expressed on a percentage basis, for each:

Table 9. Comparison of Current and Proposed Customer Charges

	Current	Proposed	% Increase
R-1	$15.39	$17.67	14.8%
R-3	$15.39	$17.37	12.8%
R-4	$8.47	$9.55	12.8%
G-41	$60.81	$67.38	10.8%
G-42	$182.42	$202.13	10.8%
G-43	$781.17	$865.55	10.8%
G-51	$60.87	$67.45	10.8%
G-52	$182.26	$201.95	10.8%
G-53	$805.75	$892.79	10.8%
G-54	$806.42	$893.53	10.8%

Table 10 shows a comparison of the volumetric rates. For the residential classes, rates are the same for all consumption levels and for all seasons. Rates for classes G-41, G-42, G-51, and G-52 are differentiated by head block and tail block, but not by season. Rates for classes G-43, G-53, and G-54 are differentiated by season but not by block.

Table 10. Comparison of Current and Proposed Volumetric Rates

	Current	Proposed	% Increase
R-1	$0.4614	$0.6834	48.1%
R-3	$0.6167	$0.7964	29.1%
R-4	$0.3392	$0.4380	29.1%
G-41			
Head block winter	$0.4928	$0.6529	32.5%
Tail block winter	$0.3390	$0.4491	32.5%
Head block summer	$0.4928	$0.6529	32.5%
Tail block summer	$0.3390	$0.4491	32.5%
G-42			
Head block winter	$0.4485	$0.5667	26.4%
Tail block winter	$0.3063	$0.3870	26.3%
Head block summer	$0.4485	$0.5667	26.4%
Tail block summer	$0.3063	$0.3870	26.3%
G-43			
Winter	$0.2766	$0.3471	25.5%
Summer	$0.1344	$0.1687	25.5%
G-51			
Head block	$0.2970	$0.4033	35.8%
Tail block	$0.1983	$0.2693	35.8%
G-52			
Head block winter	$0.2560	$0.3321	29.7%
Tail block winter	$0.1749	$0.2269	29.7%
Head block summer	$0.1891	$0.2453	29.7%
Tail block summer	$0.1132	$0.1468	29.7%
G-53			
Winter	$0.1790	$0.2255	26.0%
Summer	$0.0907	$0.1143	26.0%
G-54			
Winter	$0.0682	$0.0866	27.0%
Summer	$0.0386	$0.0490	26.9%

Q. Do these rates provide for recovery of the discount provided to customers in the R-4 and R-7 rate classes?

A. No. Revenues resulting from the discount will be recovered through the Company's LDAC mechanism.

Q. Have you calculated the GAP component of the Company's LDAC mechanism?

A. Yes. As shown at Line 106 of Schedule RATES-4, the total discount provided to customers under the GAP for the test year is $1,620,206. To calculate the GAP component of the LDAC, that amount is divided by the total delivery quantity billing determinants, 175,992,068 therms, as shown at Line 107 of RATES-4, for a result of $0.0092 per therm.

Q. Can you provide a reconciliation of the revenue requirement detailed in Mr. Culbertson and Mr. Cayton's testimony to the revenues produced by the proposed rates?

A. Yes. Schedule RATES-8 provides this reconciliation and shows that the sum of the GAP revenues and the revenues produced by the proposed rates ($121,255,425) are within 0.002% of the $121,252,410 delivery revenue requirement stated in Attachment TJC/CDC-1, Schedule RR-EN-2. The computation of the $121,255,425 is shown in Schedule RATES-4.

Q. Have you prepared a proof of the revenues that the proposed Indirect Gas Cost rates produce?

A. Yes. Schedule RATES-5 shows the revenues that will be produced by the indirect gas costs.

Q. Have you prepared a bill impact analysis?

A. Yes, I have. Schedule RATES-6 shows monthly bill impacts by class and season across a wide range of consumption levels. For each class, I estimated the total bill at each consumption level, inclusive of customer and volumetric charges, using both rates currently in effect and the proposed rates I describe above. This impact analysis also includes the GAP portion of the LDAC and the cost of gas. I have also prepared a separate schedule, RATES-7, that shows bill impacts using class average usage in the same format used in Cost of Gas Compliance filings before the Commission.

Q. If the first Step increase were combined with the proposed permanent rates mentioned above, what would be the bill impact on the residential class?

A. An average R-3 customer would see an annual increase in their total bill (inclusive of COG and GAP) of $220.09, or a 22.54% increase from the annual bill under current rates.

Q. Does this conclude your testimony?

A. Yes, it does.

THIS PAGE INTENTIONALLY LEFT BLANK