STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

<u>In the matter of</u>

Northern Utilities, Inc.

Docket No. DG 21-104

Petition for Rate Increase

DIRECT TESTIMONY

OF

Maureen L. Reno

Office of the Consumer Advocate

April 1, 2022

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I. INTRODUCTION

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

A. My name is Maureen L. Reno. My business address is 21 South Fruit Street, Suite 18, Concord, New Hampshire. I am employed as the Rates and Market Policy Director with the Office of the Consumer Advocate ("OCA").

Q. Please summarize your formal education.

A. I received a Bachelor of Arts degree in Economics from the University of Maine at Orono, Maine in 1996. In 1998, I earned a Master of Arts degree in Economics from the University of New Hampshire in Durham, New Hampshire, where I also completed all course work and examination requirements for the Ph.D. degree in Economics, except for my dissertation. My areas of academic concentration included Industrial Organization and Environmental Economics.

Q. What is your professional experience?

A I have over 20 years of professional experience in the regulated utilities and energy sectors. From 2001 to 2011, I served as a utility analyst with the New Hampshire Public Utilities Commission ("NH PUC" or the "Commission") advising the Commissioners on regulated utilities' cost of capital and return on equity ("ROE"), utility debt financings, and other regulated utility matters. From 2011 to 2012, I served as a Senior Energy Economist with the Union of Concerned Scientists, advising on the intricacies of the regulated utility industry and helping to develop alternative financing programs for renewable energy investments. Since 2012, I have served as an independent consultant to multiple firms, including Exeter Associates, Inc., TAHOEconomics, LLC, and Reno Energy Consulting Services, LLC on utility cost of capital, ROE, capital structure, rate design, and mergers and acquisitions; Stephenson Strategic Communications, LLC on federal climate and energy policy; and TrueLight Energy, LLC on competitive supplier rate impacts and energy markets. In September 2021, I joined the OCA as its Rates and Market Policy Director.

Q. Have you previously testified as an expert witness before a public utility commission?

A. Yes. My testimony was presented and accepted in more than 20 regulated utility proceedings in several states including: Arizona, Georgia, Missouri, New Hampshire, New Mexico, Oklahoma, and Texas--on a wide range of issues concerning regulated utilities, retail and wholesale energy markets, and renewable energy. (*See* Appendix A for my curriculum vitae.)

Q. Have you previously provided testimony before this Commission?

A. Yes. Please see attached to this testimony, Appendix A, for a complete list of proceedings during which I provided testimony as a utility analyst for the NHPUC Staff and recently as the Rates and Market Policy Director for the OCA.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of the Office of the Consumer Advocate.

Q. How is your testimony organized?

A. My testimony is organized into six sections, including this one. In Section II, I present the purpose of my testimony and provide my recommendations to the Commission. In Section III, I define different types of decoupling and summarize how decoupling mechanisms are implemented and the costs and benefits associated with decoupling. In Section IV, I summarize the full decoupling mechanism proposed by Northern Utilities, Inc. ("Northern" or "the Company") and present my adjustments to Northern's decoupling proposal. In Section V, I summarize my conclusions and provide my recommendations to the Commission. Section VI includes my curriculum vitae, Schedule MLR-1, and attachments.

II. PURPOSE AND RECOMMENDATIONS

Q. What is the purpose of your testimony?

A. The purpose of my testimony in this proceeding is to respond to Northern's proposed decoupling mechanism and to provide my recommendations for the Commission's consideration. Since the OCA statutorily represents the interests of residential ratepayers at large, my focus in this docket is to determine whether the Company's proposal is in the best interest of the Company's residential ratepayers.

Q. What is your approach to analyzing Northern's decoupling proposal?

A. My analysis consists of the following:

1.) I define and differentiate between various decoupling mechanisms utilized by public utility commissions across the United States.

2.) I discuss the context within which decoupling mechanisms are typically established by public utility commissions.

3.) I evaluate Northern's proposed decoupling mechanism.

4.) Finally, I provide recommendations to improve the Company's proposed decoupling mechanism.

Q. What are your recommendations for improving the Revenue Decoupling Adjustment Clause proposed by Northern as the decoupling mechanism?

A. My recommended changes to the Company's proposed Revenue Decoupling Adjustment Clause ("RDAC") include the following:

1.) All calculations for each customer class should be independently done, separate from any other customer classes.

2.) The adjustment cap should be based on distribution revenues in lieu of total revenues.

3.) The RDAC should be a semi-annual reconciliation to better match the Company's timing and submission of its cost of gas and Local Delivery Adjustment Charge ("LDAC") filings.

4.) All monthly calculations should include a monthly weather normalization adjustment.

5.) The proposed decoupling mechanism should compensate customers for the shift in risk from the Company to ratepayers by either reducing the Company's allowed return on equity or adjusting the capital structure to allow for more debt, thereby reducing the overall weighted average cost of capital.

III. DECOUPLING MECHINISMS IN GENERAL

Q. What is a decoupling mechanism?

A. Decoupling mechanisms are regulatory tools that enable states and public utilities commissions to break the traditional linkage between how much energy a utility delivers and the revenues it collects. Historically, utilities increase their revenues and, by extension, their profits by increasing their sales -- so any reduction in sales lead to reductions in revenues and profits. Decoupling diminishes or removes sales volume as a factor in utilities' revenue generation and profitability, thus reducing or eliminating their financial incentive to encourage greater consumption by customers.

Q. What is the purpose of decoupling mechanisms?

A. States and public utilities commissions have diverse reasons for wanting to break the traditional linkage between how much energy a utility delivers and the revenues it collects. Perhaps the most frequently cited, though certainly not the exclusive reason for the establishment of decoupling mechanisms, is the desire on the part of states and public utilities commissions to establish and promote energy efficiency and distributed generation programs. It is not necessarily in the financial interest of utilities to establish and promote energy efficiency and distributed generation programs because they reduce sales of electricity and natural gas to customers. These lost sales and lost contributions to fixed costs can threaten the financial viability of utilities. States and public utilities commissions may establish and approve decoupling mechanisms in order to provide a steady revenue stream to utilities, which exist to provide essential public services.

Q. Are there different types of decoupling mechanisms?

A. Yes. Many experts differentiate among full decoupling, partial decoupling, and limited decoupling mechanisms.

Q. What is a full decoupling mechanism?

A. The Regulatory Assistance Project[1] has defined full decoupling as follows:

"Decoupling in its essential, fullest form insulates a utility's revenue collections from any deviation of actual sales from expected sales. The cause of the deviation — e.g., increased investment in energy efficiency, weather variations, changes in economic activity — does not matter. Any and all deviations will result in an adjustment . . . of collected utility revenues with allowed revenues. The focus [in full decoupling] is delivering revenue to match the revenue requirement established in the last rate case. Full decoupling can be likened to the setting of a budget. Through currently used rate-case methods, a utility's revenue requirement — i.e., the total revenues it will need in a period (typically, a year) to provide safe, adequate, and reliable service — is determined. The utility then knows exactly how much money it will be allowed to collect,

[1] The Regulatory Assistance Project is an independent, non-partisan, non-governmental organization that is funded by foundations and federal contracts and is focused on the long-term economic and environmental sustainability of the energy sector. Its principals and senior associates are former regulators who have expertise in regulatory and market policies that promote economic efficiency, environmental protection, system reliability and fair allocation of system benefits among consumers.

no more, no less. Its profitability will be determined by how well it operates within that budget. Actual sales levels will not, however, have any impact on the budget."[2]

Q. What is a partial decoupling mechanism?

A. The Regulatory Assistance Project has defined partial decoupling as follows: "Partial decoupling insulates only a portion of the utility's revenue collections from deviations of actual from expected sales. Any variation in sales results in a partial true-up of utility revenues (e.g., 50 percent, or 90 percent, of the revenue shortfall is recovered)."[3]

Q. What is a limited decoupling mechanism?

A. The Regulatory Assistance Project has defined limited decoupling as follows: "Under limited decoupling only specified causes of variations in sales result in decoupling adjustments."[4] Weather normalization adjustment mechanisms, which are designed to minimize the effect of variations from normal weather on utility revenues, appear to be the most common type of limited decoupling mechanism. Under a weather normalization adjustment mechanism, a utility may apply a surcharge during winter weather that is warmer than normal and provide a credit during winter weather that is colder than normal.

Q. How common are decoupling mechanisms in the United States?

A. Based on available information provided by S&P Global in April 2020, over 21 jurisdictions have full decoupling mechanisms for a least one company and nearly 28 jurisdictions have partial or limited decoupling mechanisms. These states are not mutually exclusive – six states

[2] *Revenue Regulation and Decoupling: A Guide to Theory and Application, Regulatory Assistance Project*, 2016, p. 11. Visit the following link to download the full report: [Revenue Regulation and Decoupling: A Guide to Theory and Application (incl. Case Studies) - Regulatory Assistance Project (raponline.org)]
[3] Id., p. 12.
[4] Id.

(including New Hampshire) allow different types of mechanisms for different companies. By contrast, 10 jurisdictions do not have full or partial decoupling mechanisms.[5]

Q. What is Commission precedent regarding decoupling mechanisms?

A. The Commission first investigated decoupling as an energy efficiency rate mechanism in Docket DE 07-064, where it considered decoupling and other rate mechanism options, such as performance incentives, rate design, and reconciling rate adjustments. In Order No. 24,934 of that proceeding, the Commission averred that revenue decoupling could enhance the utility's revenue stability and reduce earnings volatility, thereby shifting risk away from the utility and toward the customer.[6] The Commission later considered its first full decoupling proposal in Docket No. DG 10-017, but the proposal was eventually withdrawn by the utility.

More recently, the Commission approved a lost revenue adjustment mechanism ("LRAM"), which is a partial or limited revenue decoupling mechanism, for all electric and gas utilities in Docket DE 15-137. In Order No. 25,932 of that proceeding, the Commission directed the utilities to seek approval of a decoupling or other lost-revenue recovery mechanism in a future rate case as an alternative to the LRAM.[7] Subsequently, in Docket DG 17-048, the Commission approved full revenue decoupling mechanisms for Liberty Utilities (EnergyNorth Natural Gas) Corporation and Liberty Utilities (Granite State Electric) Corporation.[8]

Q. What is an LRAM?

A. The LRAM is a form of limited decoupling that compensates a utility between rate cases for a hypothetical level of distribution revenues it would have otherwise received if its sales had

[5] *RRA Regulatory Focus: Alternative ratemaking plans in the U.S.*, S&P Global Market Intelligence, April 16, 2020, pp. 21-22.
[6] Docket DE 07-064, Order No. 24,934, p. 22.
[7] Docket DE 15-137, Order No. 25,932, p. 60.
[8] Docket DG 17-048, Order No. 26.122 and DE 19-064, Order No. 26,376.

not been diminished as a result of its energy efficiency program offerings. The LRAM is limited to projected revenues effects caused by approved energy efficiency programs or net metering programs and does not allow for rate adjustments due to other factors, such as changes in weather patterns and economic business cycles between rate cases.

Q. How is the Company's proposed Revenue Decoupling Adjustment Mechanism an improvement over the existing LRAM?

A. As designed, the LRAM is intended to target lost distribution revenues associated with energy efficiency and distributed generation but compensates utilities for revenues that they may not have actually lost.[9] Also, the LRAM is an asymmetric mechanism, because it only allows surcharges to customers between rate cases. The Revenue Decoupling Adjustment Mechanism ("RDAM"), in contrast, is a symmetrical mechanism that can result in either a surcharge or a credit depending upon factors outside of the Company's control, such as changes in market trends and weather. The Company proposes to replace the current LRAM regime with the RDAM.

Q. What are the benefits associated with full decoupling?

A. Since a decoupling mechanism would allow the Company to recover variances between actual revenues and allowed revenues set in the last rate case, it reduces the risk that the Company will not recover its authorized revenue requirement. Thus, the Company would benefit from stable cash flow in between rate cases. As a result, the Company would be in a better financial position to pay principal and interest owed on existing debt, thereby reducing its financial risk. Customers would benefit from rate stabilization.

Q. What are the costs associated with full decoupling?

[9] Direct Testimony of Larry Blank, DE 21-030, Bates pp. 8-9.

A. Instead of balancing risks between the utility and ratepayers, Northern's decoupling mechanism would shift all of the risk from Northern to ratepayers, which creates a moral hazard problem. In general terms, a moral hazard problem occurs when a party faces little or no accountability for its actions, thus causing it to act indifferently with respect to the outcome.[10] In this case, making the Company whole for any decline in gas sales regardless of the cause protects Northern from any risk of failure, which is antithetical to the foundational ideas of capitalism that underlie the American economy.

Q. What types of risks do investors consider with respect to their investments?

A. In addition to financial risk, an investor's expected return on an investment is composed of the risk-free rate, inflation risk, interest rate risk, business risk, and regulatory risk.

Q. What is financial risk?

A. Financial risk relates to the capital structure of a company, including its fixed contractual obligations and ability to pay interest on its debt and refinance that debt when it is due. Credit rating agencies assess the financial health of a company through the use of key financial ratios that measure the extent to which a company can pay its debt, including principal and interest. Corporate rating designations that are commonly used are shown in Table 1, which identifies rating categories used by Standard & Poor's ("S&P"), Fitch Ratings, Inc. ("Fitch"), and Moody's Investors Service ("Moody's"), for investment grade issuances.

[10] Ken Costello, *Alternative Rate Mechanisms and Their Compatibility with State Utility Commission Objectives*, National Regulatory Research Institute, 2014, p. 20. FA86C519-AF31-D926-BE12-2AC7AE0CD8D6 (naruc.org)

Table 1. Rating Categories (Investment Grade)

S&P and Fitch	Moody's
AAA	Aaa
AA+	Aa1
AA	Aa2
AA-	Aa3
A+	A1
A	A2
A-	A3
BBB+	Baa1
BBB	Baa2
BBB-	Baa3

Q. What is business risk?

A. Business risk, as perceived by investors, includes all the operating factors that increase the probability that expected future cash flows accruing to investors may not be realized. Business risk would include such factors as sales volatility and operating leverage. A utility's business risk is a function of such factors as customer base diversity, necessary capital expenditures, the regional and national economy, and inflation.

Q. What is regulatory risk?

A. Regulatory risk is based on the investor's perceived understanding of the current regulatory environment in which the utility operates along with possible changes to that regulatory environment. How regulators treat regulatory lag is one example of regulatory risk. To the extent that companies face a time lag between incurring expenses and cost recovery, such risk is best measured by choosing a proxy group of companies that face similar regulatory oversight and earn the majority of their revenues from regulated operations.

Q. What is the risk-free rate?

A. The risk-free rate is the level of return investors can achieve without assuming any risk. In general, most investors agree that an asset perceived by the market as having relatively less risk than other market bonds is a U.S. Treasury bond, because the federal government's access to tax proceeds to fulfill its debt obligations and strong credit rating makes Treasury securities practically default-free. However, Treasury bonds are not absolutely risk-free because they incorporate a risk-premium associated with interest rate risk, which is the premium investors require to compensate them for the forgone opportunity cost of an alternative higher interest rate later.

Q. What is interest rate risk?

A. Interest rate risk is the risk that arises for investors from the variability in returns caused by fluctuating interest rates, which depends on how sensitive its price is to interest rate changes in the market. For bonds, for example, its sensitivity depends on the bond's time to maturity and the coupon rate of the bond.

Q. How would Northern's proposed decoupling mechanism reduce its financial risk?

A. Without decoupling, whether a utility receives revenues that are authorized under its revenue requirement is dependent on sales and other factors outside of the control of the utility. Risk to the utility increases as earnings uncertainty increases. The uncertainty of whether a utility will achieve its authorized revenue, therefore, creates risk for the utility. Because a full decoupling mechanism would recover 100 percent of lost fixed cost and stabilize revenues, it removes the uncertainty surrounding the amount of revenue that will be received and therefore, the utility's financial risk is lowered.

Q. How do credit rating agencies address risk mitigation mechanisms that reduce a utility's risk?

A. Credit rating agencies recognize that decoupling mechanisms and other outside-the-rate-case adjustment mechanisms reduce net earnings volatility and, as a result, both financial and business risk. The Regulatory Assistance Project provides an example of how Standard & Poor's explicitly recognizes risk mitigation measures by rating the "business risk profile" of utility sector companies on a scale of 1 to 10.[11] Since credit rating agencies see decoupling mechanisms as a more transparent assurance of cost recovery that are designed to insulate cost recovery from various factors outside of management's control, such agencies see utilities with decoupling as less risky, all else equal. Since decoupling increases actual and projected cash flow from operations and, as a result, the ratio of cash flow from operations (pre-working capital) to debt increases, rating agencies have a greater tolerance for the use of leverage.[12] The Commission has acknowledged this effect of decoupling improving the Company's credit rating and thus its access to lower cost debt.[13]

Q. How does a reduction in financial and business risk affect the cost of capital?

A. Northern's proposed decoupling mechanism could affect its cost of capital in three ways. First, since credit rating agencies view full decoupling as credit positive, such agencies may upgrade Northern's credit rating, granting the Company the opportunity to access cheaper debt. Second, said credit rating agency may also tolerate a higher level of debt, thereby increasing Northern's debt portion of its capital structure and reducing the overall cost of capital, because debt is cheaper than it was before. Third, since investors associate full decoupling with lower financial and business risk, they would require a lower return.

[11] *Revenue Regulation and Decoupling: A Guide to Theory and Application*, Regulatory Assistance Project 2016 p. 37.
[12] *Decoupling and 21st Century Rate Making*, Moody's Investors Service, 2011, pp. 2-3.
[13] Docket DG 17-048, Order No. 26.122, p. 42.

Q. What is the market's assessment of the Company's financial and business risk?

A. The market's assessment of Northern's financial and business risk is set via credit ratings assigned to the Company. Northern's issuer credit rating assigned by S&P is BBB+, and its Moody's long-term rating is Baa1.[14] As of March 21, 2022, the current yield on a Baa/BBB-rated long-term (25/30-years) utility bond is 4.34 percent.[15]

Q. If the Commission were to approve Northern's full decoupling mechanism, how would credit rating agencies likely respond?

A. As discussed previously in this testimony, credit rating agencies would likely reconsider Northern's financial and business risk profile. Either they would issue a new credit rating and/or allow Northern to issue more debt at its existing credit rating. At a higher credit rating, for example an A-rated long-term bond, the current yield is 4.02 percent, which is a decrease of 32 basis points from the yield on the Baa utility bond.[16] (*See* Schedule MLR-1 for the 3-month average spread of 28 basis points.) As a result, this decrease in the cost of a single issuance would drive down the Company's cost of debt.

Q. Please summarize the process of estimating utilities' cost of capital.

A. The overall cost of capital is comprised of a utility's capital structure, the costs of long-term debt, and the cost of equity capital. In a typical rate case, the first step in estimating the cost of capital is to determine the appropriate capital structure. Long-term debt costs are computed using Northern's actual embedded costs for a certain time period (e.g., the test year). Unlike the debt component of the capital structure, the equity cost rate must be estimated. The overall

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[14] Direct Testimony of Todd R. Diggins and Andre J. Francoeur, Exhibit TDAF-1, Bates p. 563, lines 5-9.
[15] *The Value Line Investment Survey: Selection and Opinion*, Value Line, April 1, 2022 edition, p. 1957.
[16] Id.

weighted average cost of capital ("WACC") is computed by weighting individual costs of debt and equity capital by their respective proportions of total capitalization and summing the result.

The capital structure is particularly important because investors may view a high reliance on debt as risky (referred to as financial risk), thereby leading to a higher required ROE relative to similar investment opportunities. A high reliance on debt may be viewed as risky because it can contribute to earnings volatility. However, excessive equity, while reducing financial risk, may improperly increase the overall cost of capital (and therefore return on rate base) for customers.

Q. How would the reduction in the cost of debt affect the overall weighted average cost of capital?

A. If the Company received a higher credit rating, it would incur lower debt costs of new issuances, all else equal. Since the cost of debt is lower than the cost of common equity, increasing the Company's debt portion of total capitalization would reduce its overall cost of capital.

Q. How can regulators make customers whole from the Company's reduction in risk associated with full decoupling?

A. Since full decoupling reduces the cost of both debt and equity, there are two policy options to compensate ratepayers for reduced risk. The first is to lower the equity ratio since the lower credit rating will allow the utility to increase the debt portion of its capital structure at the same cost of debt, thereby lowering the overall cost of capital and revenue requirement.[17] The second policy option is to lower the allowed return on equity by a few basis points.[18] In DG 17-048, the

[17] *Revenue Regulation and Decoupling: A Guide to Theory and Application*, Regulatory Assistance Project, 2016, p. 37.
[18] Id., p. 38.

Commission previously issued a reduction in a utility's allowed return on equity by 10 basis points to account for the reduction in risk.[19]

Q. What other modifications to the Company's proposal should the Commission consider to make customers whole if it were to allow the Company to implement a full decoupling mechanism?

A. Since a full decoupling mechanism would compensate the Company for all fixed cost incurred, I recommend the Commission reject the Company's proposal to increase the residential customer charge from $22.20 to $27.84.[20] This increase of $5.64 per month (more than 25 percent) in the residential customer charge is a direct afront to New Hampshire's low-income residents. Courtney Lane and Ben Havumaki of Synapse Energy Economics, Inc. provide support to their recommendation that the Commission reject the Company's proposal to increase this customer charge.[21]

IV. NORTHERN'S PROPOSED REVENUE DECOUPLING MECHANISM AND OCA'S RECOMMENDED CHANGES

Q. Summarize the Company's proposed revenue decoupling mechanism.

A. Under the Company's proposed RDAC, the Company's proposed revenue decoupling mechanism ("RDM") is a full revenue decoupling mechanism that reconciles monthly actual and authorized revenue per customer ("RPC") by rate class and is applied to all rate classes, unlike the LRAM. The Company proposes that the authorized RPC be adjusted annually to reflect the three proposed estimated annual step increases. The proposed RDM process includes two steps. In the

[19] DG 17-048, Order No. 26,122, pp. 1, 42-43.
[20] Testimony of Ronald J. Amen and John D. Taylor, Exhibit RAJT-1, Bates 987, lines 4-8.
[21] Direct Testimony of Courtney Lane and Ben Havumaki, pp. 17-28.

first step, the Company would record the monthly variance between actual and authorized RPC for each rate class and then aggregate the variances over the twelve-month period of August through July (the "Measurement Period"). As proposed, these monthly variances would be held in a deferred account at a carrying cost equal to the Prime Rate and then aggregated over twelve-months to become the basis for the revenue decoupling adjustment ("RDA") and the calculation of the RDM adjustment factor ("RDAF") (surcharge or credit).[22] In the second step, the Company proposes to file with the Commission the applicable RDAF 45 days in advance of the annual effective date of November 1. The filing will include an allocation of the RDA, including prior reconciliation and deferrals as a result of a cap, to each rate class, and calculation of the RDAF.

Q. How is the RDAF calculated?

A. The RDAF would be a dollar per therm charge or credit based on the RDA allocated to each rate class divided by the projected therm sales for each rate class over the prospective 12-month period November through October (the "RDM Adjustment Period"). The RDAF will be charged or credited to customer bills during the RDM Adjustment Period.

Q. To which rate classes would the proposed RDM apply?

A. The Company proposes that the RDM be applicable to its Residential Heating and Non-Heating Service (Schedules R-5 and R10 combined, and R-6), Commercial and Industrial ("C&I") Service (Schedules G-40, G-41. G-50, G-51, and G-52) customer classes.

Q. Does the Company propose to limit the amount of annual adjustments?

A. Yes. The Company proposes to limit the under-recovered revenues by setting a maximum amount or an adjustment cap of 2.5 percent of total revenues from delivered sales. The amount of

[22] In Company response to Request OCA TS 2-6, the Company verified that carrying charges would be applied to all balances in the deferred account including both overcollections and undercollections of authorized revenues. See Attachment MLR-1.

under-recovered revenues that exceed this adjustment cap would be held in a deferred account with carrying costs and included in the next RDAF filing.

Q. How are the carrying costs determined?

A. The under-collected and over-collected revenues that are deposited into the deferred account would be subject to a carrying cost equal to the Prime Rate as reported by the Wall Street Journal on the first business day of the month preceding the first month of the quarter and are reset at the start of the following quarter. The Prime Rate is currently 3.5 percent.[23] The Prime Rate is also applied to the Company's carrying costs on energy efficiency costs, lost revenues, and gas assistance program included in the Company Local Delivery Adjustment Charge ("LDAC") tariff.[24]

Q. Are carrying costs expected to increase before the first effective annual period?

A. Yes. The Prime Rate is tied to the Federal Funds Rate. The Federal Reserve Bank's Open Market Committee recently stated that it expects to increase the Federal Funds Rate, among other measures, several times this year to thwart inflation.[25] Thus, the Prime Rate will likely be higher than its current level at the onset of implementing the RDAC.

Q. Do you have any concerns regarding the Company's proposed RDAC?

A. Yes. I have four concerns. First, I am concerned about the aggregation of monthly variances across all rate classes and then reallocating that total back to the customer classes when not all customer classes will share equally in the need for an adjustment.[26] Although the Company claims that the proposed approach results in a consistent direction and magnitude of revenue

[23] Visit the following site for the latest Prime Interest Rate Money Rates (wsj.com) *See also* Company Response to Request OCA 1-19. Included here as Attachment MLR-2.
[24] Company Response to Request OCA 2-39. Included here as Attachment MLR-3.
[25] Federal Reserve Board - Monetary Policy Federal Reserve Press Release dated March 16, 2022 and included here as Attachment MLR-4.
[26] Company Response to Request OCA TS 1-4 and Attachment 1. Included here as Attachment MLR-5.

adjustments across rate classes, it would lead to a deviation from the revenue requirements approved by the Commission in the rate case. Under this proposal, it is also highly possible that a customer class would be paying a surcharge when it actually should be receiving a credit due to an over-collection of revenue in the previous period(s), such as when the under-recovery of other rate classes is greater than over-recovered revenue for that one rate class.

Q. How do you propose to remedy the problems that would arise from aggregating the monthly variances across all rate classes?

A. Ideally, a revenue decoupling mechanism should be designed such that any over- and under-recovery is calculated independently within each rate class. However, the Company avers that this process would be administratively burdensome.[27] In the recent electric general rate case involving the Company's electric distribution affiliate in New Hampshire, Docket No. DE 21-030, Unitil agreed in settlement to apply individual rate class grouping reconciliations.[28] Other gas utilities, such as EnergyNorth Natural Gas (Liberty), calculate the revenue decoupling adjustment separately for Residential and C&I rate classes.[29]

An acceptable alternative would be to group both the residential and C&I customer classes by load factor for the purpose of applying revenue per customer to calculate the revenue decoupling adjustment in lieu of simply using that aggregation of monthly variances. Grouping rate classes by load factor is a reasonable approach since low-load factor classes tend to have a higher variation in natural gas usage related to weather since they use significantly more gas during colder winter months for heating, while the high-load factor classes maintain a more consistent

[27] Company Response to Request OCA TS 1-4. Included here as Attachment MLR-5.
[28] Company Response to Request OCA TS 2-3. Included here as Attachment MLR-6.
[29] Id.

and lower overall annual level of gas consumption.[30] The difference in load factor is also due to energy efficiency measures associated with heating equipment. Thus, the residential heating (R-5 and R-10) and non-heating (R-6) rate classes would have their own monthly variances to determine the rate adjustment. Similarly, the C&I rate classes would be grouped together based on load factors such that rate classes G-50, G-51, and G-52 would be grouped together due to a high load factor and the G-40, G-41, and G-42 rate classes would be grouped together due to a low load factor.

Q. What is your recommendation regarding the treatment of variances and the resulting revenue per customer?

A. To preserve the rate design principles of fairness and efficiency, I recommend the Commission direct the Company to calculate the RDAF for a customer class strictly from over- and under-recovery within that class without any aggregation of variances across customer classes or, in the alternative, to group the residential and C&I customer classes by load factor for the purpose of applying revenues per customer to calculate the revenue decoupling adjustment. Following completion of the new groupings for application of revenues per customer, I recommend the Commission direct the Company to apply them to the distribution revenue allocator resulting in four segments of allocated distribution revenues: (1) R-6 residential non-heating classes; (2) R-5 and R-10 residential heating classes; (3) G-40, G-41, and G-42 C&I customer classes; and (4) G-50, G-51, and G-52 C&I customer classes.

Q. What is your second concern regarding the Company's proposal?

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[30] This is the method employed by Company's Massachusetts affiliate Fitchberg Gas and Electric Light Company. Evidence provided by the Massachusetts Attorney General showed that high-load factor C&I classes using less gas in the winter pay disproportionately more of the revenue decoupling adjustment than their low-load factor C&I class counterparts, especially among small and medium C&I customers. *See* D.P.U. 15-80/D.P.U. 15-81 Order issued April 29, 2016, at 22-23.

A. My second concern regarding the Company's proposed RDAC is that the Company's proposed cap on revenue decoupling adjustments is set at 2.5 percent of total revenues from delivered sales for the most recent twelve-month period.[31] The variability of total revenues from year-to-year due to the volatile nature of the cost of gas and resulting rates could lead to large variations in the RDAF that would violate the principal of rate continuity.

Q. How do you propose to fix the rate continuity problem that would arise from setting the adjustment cap equal to 2.5 percent of total revenues?

A. As an alternative, I recommend the Commission require the Company to set its adjustment cap based on distribution revenues. This recommendation is also in-line with the treatment of the adjustment cap set in the settlement agreement reached in the Unitil electric rate case, DE 21-030.[32] Using the Company's proposed 2.5 percent adjustment cap on total revenues to calculate a 4.2 percent cap on distribution revenues leaves the Company whole with regard to the revenues allowed through the mechanism.[33]

Q. What is your third concern regarding the Company's proposal?

A. Third, I am concerned that the Company's proposal for an annual RDAC fails to address the variation in revenue that exists between peak and off-peak periods.

Q. How do you propose to correct for the variation in total revenue that exist between peak and off-peak period?

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[31] Direct Testimony of Timothy S. Lyons, Bates p. 1076, lines 14-15.
[32] Company Response to Request OCA TS 2-3. Included here as Attachment MLR-6.
[33] The 4.2 percent adjustment cap based on distribution revenues is derived using the Test Year total operating revenue of $66,683,473 and test year distribution revenues of $39,344,949 and applying the following formula: [($66,683,473*0.025)/($39,344,949)]=0.042. *See* Attachment MLR-7 Company Response to Request Energy 1-11 Attachment 1, "2 Inc State P1" worksheet.

A. I recommend the Commission direct the Company to rely on separate peak and off-peak total revenue calculations to match the reconciliation methods for peak and off-peak cost of gas and LDAC components.

Q. What is your fourth concern regarding the Company's proposal?

A. Fourth and finally, I am concerned that the Company's proposal for an annual RDAC lacks a weather normalization adjustment. Traditionally, gas utility rates are set assuming normal weather conditions. Any fluctuations in revenues due to abnormal weather are absorbed by the Company until its next rate case. Such an adjustment for weather would stabilize cash flow and result in rate continuity. The Company's proposed RPC, which is set on weather normalized test year revenue levels, fails to address the risk of colder or warmer temperature that customers face.

Q. How do you propose to correct for this lack of a weather normalization adjustment?

A. I recommend the Commission direct the Company to weather-normalize the actual revenue realized in addition to the allowed revenues such that the weather normalized allowed revenues and the weather normalized actual revenues would be used for the basis of the rate adjustment.

Q. Do you have any concerns regarding the Company's step adjustments?

A. Yes. The Company proposes that the authorized revenues per customer be adjusted annually to reflect the three step increases on August 1, 2022, August 1, 2023, and August 1, 2024. Courtney Lane and Ben Havumaki of Synapse Energy Economics recommend on behalf of the OCA that the Commission reject the Company's proposal for implementing such step increases.[34] If the Commission were to heed this recommendation, then the allowed RPC used to calculate the variances should be based on the allowed RPC set at the end of the test year.

[34] Direct Testimony of Courtney Lane and Ben Havumaki, p. 15: line 13 to p. 16: line 10.

V. CONCLUDING REMARKS AND RECOMMENDATIONS

Q. Before providing your recommendation, please summarize your analyses above.

A. Although the Company's proposed full decoupling mechanism is an improvement compared to the LRAM paradigm, the Commission must proceed with caution and consider how customers would face additional risk typically borne by the utility absent such a mechanism. Therefore, if the Commission were to approve the Company's proposal, it should also require the Company to make my recommended changes to provide rate continuity and make customers whole.

Q. Given your analyses discussed above, what are your recommendations?

A. My recommended changes to the Company's proposed RDAC include the following:

1.) All calculations for each customer class should be made separately from any other customer classes.

2.) The adjustment cap should be based on distribution revenues in lieu of total revenues.

3.) The RDAC should be a semi-annual reconciliation to better match the Company's timing and submission of its cost of gas and LDAC filings.

4.) All monthly calculations should include a monthly weather normalization adjustment.

5.) Customers should be compensated for the shift in risk to them by either reducing the Company's allowed return on equity or adjusting the capital structure to allow for more debt, thereby reducing the Company's WACC.

Q. Does this conclude your testimony?

A. Yes, it does. However, I reserve the right to supplement my testimony as new information becomes available.

Appendix, Schedule and Attachments

Maureen L. Reno

21 South Fruit St, Suite 18
Concord, New Hampshire 03301-2429
Tel: (603) 271-1175
Email: Maureen.l.reno@oca.nh.gov

Maureen Reno is a seasoned expert with 20 years of experience in the field of public utility regulation. After she completed her Ph.D. studies in Economics at the University of New Hampshire, Ms. Reno launched her career in public utility regulation as a utility analyst and program manager at the New Hampshire Public Utilities Commission, where she worked for the next 10 years. In this capacity, she provided expert testimony on rate of return (to include return on equity) in electricity, natural gas, and water utility rate cases. Ms. Reno also led the development and implementation of New Hampshire's Renewable Portfolio Standard program, helping both owners of distributed generation and load serving entities meet compliance requirements and maneuver the dynamic wholesale energy and renewable energy certificate markets. In addition, she managed New Hampshire's participation in the Regional Greenhouse Gas Initiative.

Subsequently, Ms. Reno served as a Senior Energy Economist with the Union of Concerned Scientists. In this capacity, she developed clean energy financing policies and advocated for electricity sector solutions to global warming.

Since 2012, Ms. Reno has served as an independent consultant, working with other small businesses to advise government and industry clients on diverse utility-related matters. In addition, she has served as an expert witness on rate design and rate of return (to include return on equity) in numerous cases. Her testimony has been presented to public utility commissions across the United States, to include the Arizona Corporation Commission, Georgia Public Service Commission, Missouri Public Service Commission, the New Mexico Public Regulation Commission, the Oklahoma Corporation Commission, and the Public Utility Commission of Texas.

Ms. Reno stays abreast of the latest developments in utility regulatory law and policy through her research and professional activities. Given the complexity of Federal and state regulations that affect her clients, Ms. Reno dedicates significant time and energy to reviewing regulatory developments enacted by the U.S. Department of Energy, the Federal Energy Regulatory Commission (FERC), and the U.S. Environmental Protection Agency.

Ms. Reno currently serves the interests of residential rate payers in New Hampshire as the Rate and Market Policy Director at the New Hampshire Office of the Consumer Advocate.

EDUCATION

- Completed all course work and exam requirements towards the Doctorate of Philosophy in Economics – University of New Hampshire, Durham.
  Fields of Specialization: Industrial Organization and Environmental Economics
- Master of Arts in Economics – University of New Hampshire, Durham, 1998
- Bachelor of Arts in Economics – University of Maine, Orono, 1996

PROFESSIONAL EXPERIENCE

- Rate and Market Policy Director, New Hampshire Office of the Consumer Advocate (2021-Present)
- Independent Consultant (2012-Present)
- Senior Energy Economist, Union of Concerned Scientists (2011-2012)
- Analyst, Program Manager, Utility Analyst, and Economist, New Hampshire Public Utilities Commission (2001-2011)
- Survey Manager, New Hampshire Small Business Development Center (1999-2001)
- Adjunct Instructor, University of New Hampshire (1999-2001)

EXPERT WITNESS TESTIMONY

- Before the New Hampshire Public Utilities Commission, Case No. DG 21-036, on behalf of the Office of the Consumer Advocate. Testimony regarding the cost-effectiveness of a Renewable Natural Gas Supply and Transportation Agreement between Liberty Utilities and RUDARPA North Country, LLC.
- Before the Texas Public Utility Commission, Docket No. 52195, on behalf of the U.S. Department of Defense. Testimony regarding a fair return on equity for El Paso Electric Company.
- Before the New Mexico Public Regulation Commission, Case No. 20-00222-UT, on behalf of Bernalillo County. Testimony regarding the net benefits and risks of Avangrid Network's Merger and Acquisition of Public Service Company of New Mexico.
- Before the New Mexico Public Regulation Commission, Case No. 20-00121-UT, on behalf of Bernalillo County. Testimony regarding Rate Design (specifically, Decoupling Rate Adjustment Mechanism) for Public Service Company of New Mexico.
- Before the New Mexico Public Regulation Commission, Case No. 19-00170-UT, on behalf of Commission Staff. Testimony regarding a fair return on equity for Southwestern Public Service Company.
- Before the Georgia Public Service Commission, Docket No. 42516, on behalf of the U.S. Department of Defense and all other Federal Executive Agencies. Testimony regarding Rate Design (specifically, Impact of Alternative Rate Plan and Rate Adjustment Mechanism on Company Risk), Cost of Capital, and Return on Equity for Georgia Power Company.
- Before the Arizona Corporation Commission, Docket No. E-01933A-19-0028, on behalf of the U.S. Department of Defense and all other Federal Executive Agencies. Testimony regarding a fair return on equity for Tucson Electric Power Company.

- Before the New Mexico Public Regulation Commission, Case No. 18-00124-UT, on behalf of the City of Clovis, New Mexico. Testimony regarding a fair return on equity for EPCOR Water New Mexico Inc.
- Before the Oklahoma Corporation Commission, Cause No. PUD 201700151, on behalf of the U.S. Department of Defense and all other Federal Executive Agencies. Testimony regarding a fair return on equity for Public Service Company of Oklahoma.
- Before the Oklahoma Corporation Commission, Cause No. PUD 201500208, on behalf of the U.S. Department of Defense and all other Federal Executive Agencies. Testimony regarding Rate Design (specifically, Environmental Compliance Rider and Impact on Company Risk), Cost of Capital, and Return on Equity for Public Service Company of Oklahoma.
- Before the Texas Public Utility Commission, Docket No. 43695, on behalf of the U.S. Department of Energy. Testimony regarding a fair return on equity for Southwestern Public Service Company.
- Before the Missouri Public Service Commission, Case No. ER-2014-0370, on behalf of the U.S. Department of Energy. Testimony regarding a fair return on equity for Kansas City Power & Light Company.
- Before the Texas Public Utility Commission, Docket No. 41791, on behalf of the U.S. Department of Energy. Testimony regarding a fair return on equity for Entergy Texas, Inc.
- Before the New Hampshire Public Utilities Commission, Docket No. DE 05-178, on behalf of Commission Staff. Testimony regarding the Rate of Return for Unitil Energy Systems, Inc.
- Before the New Hampshire Public Utilities Commission, Docket No. DE 04-177 on behalf of Commission Staff. Testimony regarding the Rate of Return for Public Service Company of New Hampshire’s generation assets.
- Before the New Hampshire Public Utilities Commission, Docket No. DW 04-056 on behalf of Commission Staff. Testimony regarding the Rate of Return for Pennichuck Water Works, Inc.
- Before the New Hampshire Public Utilities Commission, Docket No. DE 03-200 on behalf of Commission Staff. Testimony regarding the Rate of Return for Public Service Company of New Hampshire.
- Before the New Hampshire Public Utilities Commission, Docket No. DE 03-166 on behalf of Commission Staff. Testimony regarding the Modification of Schiller Station for Public Service Company of New Hampshire.
- Before the New Hampshire Public Utilities Commission, Docket No. DE 01-247 on behalf of Commission Staff. Testimony regarding the Rate of Return for Concord Electric Company and Exeter & Hampton Electric Company.
- Before the New Hampshire Public Utilities Commission, Docket No. DE 01-168 on behalf of Commission Staff. Testimony regarding the Refinancing of Series A, B and C Pollution Control Revenue Bonds, Including an Increase in the Short-term Debt Limit, Issuance of First Mortgage Bonds and Utilization of Derivative Instruments for Public Service Company of New Hampshire.

- Before the New Hampshire Public Utilities Commission, Docket No. DG 01-182 on behalf of Commission Staff. Testimony regarding the Rate of Return for Northern Utilities, Inc.
- Before the New Hampshire Public Utilities Commission, Docket No. DW 01-081 on behalf of Commission Staff. Testimony regarding the Rate of Return for Pennichuck Water Works, Inc.

UTILITY-RELATED MATTERS

As an independent consultant and owner of Reno Energy Consulting Services, LLC, Ms. Reno:

- Provided written testimony on behalf of Bernalillo County in an electric utility rate case. Evaluated Public Service Company of New Mexico ("PNM")'s proposed Decoupling Rate Adjustment Mechanism and assessed the impacts of PNM's proposal on ratepayers, business and financial risk, and the cost of capital.
- Provided written testimony on behalf of New Mexico Public Regulation Commission Staff in an electric utility rate case. Assessed Southwestern Public Service Company's weighted average cost of capital and estimated the rate of return on equity using discounted cash flow, risk premium, and capital asset pricing models.
- Provided written and oral testimony on behalf of large federal executive agencies, such as the U.S. Department of Defense and the U.S. Department of Energy, in electric utility rate cases before the Arizona Corporation Commission, Georgia Public Service Commission, Missouri Public Service Commission, Corporation Commission of Oklahoma, and the Public Utility Commission of Texas. Assessed each utility's weighted average cost of capital and estimated the rate of return on equity using discounted cash flow, risk premium, and capital asset pricing models.
- Prepared the financial analysis and ratepayer impacts of a long-term contract requirement under Maryland's RPS for the Power Plant Research Program (PPRP) on behalf of the Maryland Department of Natural Resources. The report titled "Final Report Concerning the Maryland Renewable Portfolio Standard as Required by Chapter 393 of the Acts of the Maryland General Assembly of 2017" was publicly released in December 2019.
- Evaluated utility proposals for deployment, cost-benefit analysis, and cost recovery of Maryland's Statewide Electric Vehicle Portfolio on behalf of the Maryland Energy Administration through the PPRP in Case No. 9478 In the Matter of the Petition of the Electric Vehicle Work Group for Implementation of a Statewide Electric Vehicle Portfolio.
- Conducted research and drafted sections of regional energy market operations manuals for the US Department of Energy's Federal Energy Management Program. The reports focused on how federal facilities were pursuing renewable energy development under different market constructs, such as by vertically integrated electric utilities, electric utilities with the PJM footprint, and electric utilities in California, and how those market constructs affected the prospects for future renewable energy development.

As an independent consultant for Stephenson Strategic Communications LLC, Ms. Reno:

- Provided consulting services to build support in New Hampshire for strong national climate and energy policies on behalf of a nationally recognized, non-profit environmental organization.
- Mobilized experts and leaders in New Hampshire to engage elected federal, state and locals official through targeted senator visits, media interviews, public events, letters to the editor, and opinion and editorial articles.
- Communicated directly with targeted legislators and their staff to determine their positions on climate and clean air policies and address their concerns.

As an independent consultant for TrueLight Energy LLC, Ms. Reno:

- Acted as director of regulatory affairs to expand upon current services to provide clients with guidance on how to navigate the dynamic deregulated electricity industry.
- Developed regulatory service product for clients, to include ISO/utility tariff tracking and rate impact analysis, policy analysis, new market identification and participation in regulatory processes.
- Identified and originated new commercial opportunities in the United States to support principal product/service lines: retail supplier solutions; generation asset management; and sustainability management solutions for large energy users.
- Developed and implemented business development and business-to-business marketing strategies in coordination with senior management.

As a senior energy economist at the Union of Concerned Scientists, Ms. Reno:

- Promoted the development of clean energy technologies and policies in the electricity sector. Designed and evaluated energy policies at the state, regional, and national levels to maximize economic benefits and overcome market barriers to renewable energy.
- Evaluated and developed alternative financial policies to national and state renewable energy standards. Completed internal documents and research focusing on master limited partnerships and real estate investment trusts as possible sources of financing capital for renewable energy projects.
- Informed and enhanced coalition strategies by evaluating and developing appropriate responses to federal policy opportunities, including a low-carbon electricity standard, production tax credit, and other emerging opportunities.
- Evaluated the net benefits and opportunities for economic development in renewable energy manufacturing and the supply chain.

As an analyst and program manager at the New Hampshire Public Utilities Commission, Ms. Reno:

- Developed internal protocols for managing New Hampshire's RPS program pursuant to NHPUC's RPS program rules (N.H. Code of Administrative Rules PUC 2500), including designing resource eligibility application forms.

- Verified electricity providers' compliance with New Hampshire's RPS program and processed applications for renewable energy source eligibility.
- Prepared and submitted annual RPS compliance reports, including program evaluation and policy analysis, to the State legislature on behalf of the NHPUC.
- Monitored and forecasted renewable energy certificate market trends in New England and New Hampshire to estimate available revenues supporting rebate programs.
- Maintained an RPS program website and renewable energy sources database.
- Participated in various regional working groups, including the Regional Greenhouse Gas Initiative ("RGGI") Allowance Auction and Offset Market Groups, and the New England Power Pool Generation Information System ("NEPOOL GIS") Regulators' Caucus to help develop and maintain the NEPOOL GIS Operating Rules.
- Developed Greenhouse Gas Emissions Reduction Fund Cost Effectiveness Analysis model for request for proposal applicants.

As a utility analyst and economist at the New Hampshire Public Utilities Commission, Ms. Reno:

- Reviewed, analyzed and prepared oral and written recommendations in eight electric, natural gas and water utility rate cases in which she calculated each company's weighted average cost of capital and estimated the rate of return on equity using discounted cash flow, risk premium, and capital asset pricing models.
- Reviewed, analyzed and prepared oral and written recommendations for the PUC on utility requests for changes in energy service rate charges and other surcharges reflected in utility company tariffs.
- Advised the Commissioners on utilities' debt financings, bond issuances, power plant retrofit, advanced/net metering, demand response, environmental disclosure, and incentives for in-state energy efficiency programs.
- Collaborated on behalf of the NHPUC with public and private entities to write New Hampshire's RPS law (HB 873), law concerning state participation in RGGI (HB 1434) and the NHPUC's RPS program rules (N.H. Code of Administrative Rules Puc 2500).
- Advised the Commissioners on the development of the RGGI carbon dioxide emission limits and the Allowance Auction Market.
- Assisted researchers at the University of New Hampshire in estimating the net benefits of New Hampshire's RPS and its participation in RGGI for the state legislature, which included environmental and economic development benefits.
- Advised the Commissioners on RGGI's impact on regional and state economies by serving on the RGGI Modeling Subgroup and helped the Northeast States for Coordinated Air Use Management develop the Northeast version of the MARKAL (MARKet Allocation) model.
- Prepared fiscal impact statements regarding proposed legislation and regulations in the State of New Hampshire using cost-benefit analysis and estimated ratepayer impacts.

As a Survey Manager for the New Hampshire Small Business Development Center, Ms. Reno:

- Designed and distributed a survey to collect data on the characteristics of New Hampshire manufacturers.
- Managed survey data collection, designed a database for the data collected, and oversaw data entry efforts.
- Analyzed the economic and behavioral factors that lead to the growth of New Hampshire manufacturing companies using multivariate regression, factor and cluster analysis of survey data.

As an Adjunct Instructor for the University of New Hampshire, Ms. Reno:

- Taught undergraduate courses in Principles of Macroeconomics and Microeconomics (to include daily lectures) and developed lesson plans and teaching materials.
- Managed teaching assistant's work correcting and grading testing materials and writing assignments.

RESEARCH

- Conference Paper – "The Effect of Rate and Energy Efficiency Policies on Electricity Demand: Evidence from New Hampshire" by Chris Schlegel and Maureen L. Sirois, presented at the 22nd Annual Eastern Conference of the Advanced Workshop in Regulation and Competition, Skytop, PA, May 2003.
- Dissertation for Ph.D. – "Participation in Environmental Management Systems: The Effect of Supply-Chain Relationships on Company Behavior," presented at the Eastern Economic Association meeting, New York City, NY, February 2001.
- Report under the Manufacturing Management Grant – "Report on U.S. Small Business Administration Funded Survey of New Hampshire Manufacturers in Rural Areas," by Linda G. Sprague and Maureen L. Sirois, presented at the Global Manufacturing Research Group (GMRG) Annual Meeting, University of Western Ontario, Canada, August 2000.

Schedule MLR-1 Utility Bond Yields			
	Utility (25/30-yr) A-Rated	**Utility (25/30-yr) Baa/BBB-Rated**	**Utility Bond Yield Spread**
12/20/2021	3.02	3.26	**0.24**
12/27/2021	3.03	3.28	**0.25**
1/3/2022	3.18	3.41	**0.23**
1/10/2022	3.25	3.49	**0.24**
1/14/2022	3.28	3.52	**0.24**
1/24/2022	3.32	3.57	**0.25**
1/31/2022	3.40	3.65	**0.25**
2/7/2022	3.53	3.79	**0.26**
2/14/2022	3.66	3.93	**0.27**
2/18/2022	3.68	3.96	**0.28**
2/28/2022	3.68	3.99	**0.31**
3/7/2022	3.77	4.10	**0.33**
3/14/2022	3.98	4.44	**0.46**
3/21/2022	4.02	4.34	**0.32**
Average	**3.49**	**3.77**	**0.28**
Median	**3.47**	**3.72**	**0.26**

Source: *Value Line Investment Survey: Selection & Opinion* , Weekly Issues from December 31, 2021 to April 1, 2022.

Northern Utilities, Inc.
Docket No. DG 21-104
OCA Data Requests – Tech Session Set 2

Date Request Received: 3/2/22 | Date of Response: 3/11/22
Request No. OCA TS 2-6 | Witness: Timothy Lyons

REQUEST:

Refer to Company Response to Request No. OCA 2-39, Witness Timothy S. Lyons, and answer the following:

a. Please clarify whether the carrying costs will apply to all balances in the deferred account or to the balances that exceed the cap. Company response to OCA 2-39 (a.) states that revenue shortfalls exceeding the 2.5 percent cap will be held in a deferred account with carrying costs, however Bates 1066, lines 6-9 states that the total amount of variances would be held in a deferred account with a carrying charge. So, which is it?
b. Also, would this carrying charge be charged to overcollections that would be credited to customers?

RESPONSE:

a. Carrying charges will be applied to all balances in the deferred account, including revenue shortfalls exceeding the 2.5 percent cap.

b. Yes, carrying charges will be applied on overcollection of authorized revenues as well as undercollection of authorized revenues.

Northern Utilities, Inc.
Docket No. DG 21-104
OCA Data Requests – Set 1

Date Request Received: 12/6/2021 Date of Response: 12/20/2021
Request No. OCA 1-19 Witness: Timothy S.Lyons

REQUEST:

Reference Lyons Testimony Bates Page 1074, Lines 13-18.

a. What is the current Prime Rate?
b. What is the expected Prime Rate during the first effective annual period?
c. When will the carrying cost change as a result of a change in the Prime Rate?
d. Will the carrying cost change in the following month or the following year?

RESPONSE:

a. The current Prime Interest Rate is 3.25 percent. Please refer to OCA 1-19 Attachment 1.

b. The proposed revenue decoupling mechanism takes effect on August 1, 2022; thus, the first effective annual period is August 1, 2022 through July 31, 2023. The Prime Interest Rate during the first effective annual period will be the Prime Interest Rate, as reported by the Wall Street Journal on the first business day of the month preceding the first month of the quarter, consistent with Section IX of the Company's proposed tariff in Schedule TSL-2, page 3 of 6.

   Thus, the Prime Interest Rate for the first effective annual period of August 1, 2022 through July 31, 2023 will be the Prime Interest Rate, as reported by the Wall Street Journal on the first business day of:
   - June 2022 (to calculate carrying costs for August-September 2022)
   - September 2022 (to calculate carrying costs for October-December 2022)
   - December 2022 (to calculate carrying costs for January-March 2023)
   - March 2023 (to calculate carrying costs for April-June 2023)
   - June 2023 (to calculate carrying costs for July 2023),

c. Carrying charges remain in effect for the quarter and are reset at the start of the following quarter, subject to changes in the Prime Interest Rate.

d. Carrying charges change only at the start of a quarter (i.e., January 1st, April 1st, July 1st and October 1st), subject to a change in the Prime Interest Rate. In other words, carrying charges remain in effect for the quarter and are reset only at the start of the following quarter, subject to changes in the Prime Interest Rate.

Northern Utilities, Inc.
Docket No. DG 21-104
OCA Data Requests – Set 2

Date Request Received: 2/10/2022 Date of Response: 2/24/2022
Request No. OCA 2-39 Witness: Timothy S. Lyons

REQUEST:

Lyons Testimony, Bates p. 1076: lines 13-20, and answer the following:

a. Please explain what happens to the revenue shortfalls that exceed the 2.5 percent cap.
b. Has the Company considered a maximum amount of revenue shortfalls to be held in the deferred account?
c. Please explain the rationale of applying a carrying cost to the balances in the deferred account.
d. Is applying carrying costs to balances in the deferred account typical practice for utilities with a decoupling mechanism? If so, provide support.
e. Is the deferred account a revolving credit facility or a short-term loan to the Company?
f. Please explain the rationale of not applying the adjustment cap in the case of a revenue surplus.

RESPONSE:

a. Revenue shortfalls exceeding the 2.50 percent cap are held in a deferred account with carrying costs and included in the next RDAF filing.

b. No. The Company believes the proposed revenue decoupling cap of 2.50 percent strikes an appropriate balance between two objectives: (1) the timely collection of a revenue shortfall; and (2) the avoidance of a large revenue decoupling-related rate increase. A revenue decoupling cap that was too low, for example, could lead to frequent delays in collection of a revenue shortfall. An important element of revenue decoupling is that it removes the Company's disincentive to encourage energy efficiency by removing the link between its revenues and sales. A cap that is too low has a similar effect (provides a disincentive to encourage energy efficiency), as the Company would be unable to collect its authorized revenue on a timely basis. Conversely, a revenue decoupling cap that was too high could lead to large revenue decoupling-related rate increases. The proposed cap of 2.50 percent strikes the appropriate balance between those objectives. Figure 1 in the Company's response to OCA 1-20 shows historically most decoupling adjustments have been symmetrical and generally within the range of +/- 2.50 percent.

Northern Utilities, Inc.
Docket No. DG 21-104
OCA Data Requests – Set 2

Date Request Received: 2/10/2022 | Date of Response: 2/24/2022
Request No. OCA 2-39 | Witness: Timothy S. Lyons

c. Carrying costs reflect the time value of money in the deferred account.

d. The Company has not performed research on utilities who apply carrying costs to revenue decoupling deferred balances; however, the Company has prepared in **Table 1 (below)** a partial list of nearby gas and electric utilities that apply carrying costs on revenue decoupling deferred balances, including two utilities in New Hampshire.

Table 1: Partial List of Nearby Utilities with Carrying Costs

Utility	Tariff
New Hampshire	
Liberty Utilities (Gas)	OCA 2-39 Attachment 1
Liberty Utilities (Electric)	OCA 2-39 Attachment 2
Massachusetts	
Fitchburg Gas and Electric (Gas)	OCA 2-39 Attachment 3
Fitchburg Gas and Electric (Electric)	OCA 2-39 Attachment 4
National Grid – Boston Gas	OCA 2-39 Attachment 5
Liberty Utilities – New England Gas	OCA 2-39 Attachment 6
Eversource – NSTAR Gas	OCA 2-39 Attachment 7
Berkshire Gas	OCA 2-39 Attachment 8
Eversource – NSTAR Electric	OCA 2-39 Attachment 9

e. Carrying costs are based on the prime rate, consistent with the Company's carrying costs on energy efficiency costs, lost revenues, and gas assistance program included in the Company Local Delivery Adjustment Charge tariff, as included in OCA 2-39 Attachment 10.

f. Not applying a cap in the case of a revenue surplus ensures customers receive their refund without delay.

FEDERAL RESERVE press release

For release at 2 p.m. EDT March 16, 2022

Indicators of economic activity and employment have continued to strengthen. Job gains have been strong in recent months, and the unemployment rate has declined substantially. Inflation remains elevated, reflecting supply and demand imbalances related to the pandemic, higher energy prices, and broader price pressures.

The invasion of Ukraine by Russia is causing tremendous human and economic hardship. The implications for the U.S. economy are highly uncertain, but in the near term the invasion and related events are likely to create additional upward pressure on inflation and weigh on economic activity.

The Committee seeks to achieve maximum employment and inflation at the rate of 2 percent over the longer run. With appropriate firming in the stance of monetary policy, the Committee expects inflation to return to its 2 percent objective and the labor market to remain strong. In support of these goals, the Committee decided to raise the target range for the federal funds rate to 1/4 to 1/2 percent and anticipates that ongoing increases in the target range will be appropriate. In addition, the Committee expects to begin reducing its holdings of Treasury securities and agency debt and agency mortgage-backed securities at a coming meeting.

In assessing the appropriate stance of monetary policy, the Committee will continue to monitor the implications of incoming information for the economic outlook. The Committee would be prepared to adjust the stance of monetary policy as appropriate if risks emerge that could impede the attainment of the Committee's goals. The Committee's assessments will take into account a wide range of information, including readings on public health, labor market conditions, inflation pressures and inflation expectations, and financial and international developments.

(more)

For release at 2 p.m. EDT March 16, 2022

-2-

Voting for the monetary policy action were Jerome H. Powell, Chair; John C. Williams, Vice Chair; Michelle W. Bowman; Lael Brainard; Esther L. George; Patrick Harker; Loretta J. Mester; and Christopher J. Waller. Voting against this action was James Bullard, who preferred at this meeting to raise the target range for the federal funds rate by 0.5 percentage point to 1/2 to 3/4 percent. Patrick Harker voted as an alternate member at this meeting.

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For release at 2 p.m. EDT March 16, 2022

Decisions Regarding Monetary Policy Implementation

The Federal Reserve has made the following decisions to implement the monetary policy stance announced by the Federal Open Market Committee in its statement on March 16, 2022:

- The Board of Governors of the Federal Reserve System voted unanimously to raise the interest rate paid on reserve balances to 0.4 percent, effective March 17, 2022.
- As part of its policy decision, the Federal Open Market Committee voted to authorize and direct the Open Market Desk at the Federal Reserve Bank of New York, until instructed otherwise, to execute transactions in the System Open Market Account in accordance with the following domestic policy directive:

  "Effective March 17, 2022, the Federal Open Market Committee directs the Desk to:
    - Undertake open market operations as necessary to maintain the federal funds rate in a target range of 1/4 to 1/2 percent.
    - Conduct overnight repurchase agreement operations with a minimum bid rate of 0.5 percent and with an aggregate operation limit of $500 billion; the aggregate operation limit can be temporarily increased at the discretion of the Chair.
    - Conduct overnight reverse repurchase agreement operations at an offering rate of 0.3 percent and with a per-counterparty limit of $160 billion per day; the per-counterparty limit can be temporarily increased at the discretion of the Chair.
    - Roll over at auction all principal payments from the Federal Reserve's holdings of Treasury securities and reinvest all principal payments from the Federal Reserve's holdings of agency debt and agency mortgage-backed securities (MBS) in agency MBS.
    - Allow modest deviations from stated amounts for reinvestments, if needed for operational reasons.
    - Engage in dollar roll and coupon swap transactions as necessary to facilitate settlement of the Federal Reserve's agency MBS transactions."
- In a related action, the Board of Governors of the Federal Reserve System voted unanimously to approve a 1/4 percentage point increase in the primary credit rate to 0.5 percent, effective March 17, 2022. In taking this action, the Board approved requests to establish that rate submitted by the Boards of Directors of the Federal Reserve Banks of Boston, Philadelphia, Cleveland, Richmond, Atlanta, Chicago, St. Louis, Minneapolis, Kansas City, and San Francisco.

(more)

This information will be updated as appropriate to reflect decisions of the Federal Open Market Committee or the Board of Governors regarding details of the Federal Reserve's operational tools and approach used to implement monetary policy.

More information regarding open market operations and reinvestments may be found on the Federal Reserve Bank of New York's website.

Northern Utilities, Inc.
Docket No. DG 21-104
OCA Data Requests – Tech Session Set 1

Date Request Received: 1/27/22	Date of Response: 2/10/22
Request No. OCA TS 1-4	Witness: Timothy S. Lyons

REQUEST:

Refer to Lyons Testimony, Bates Page 1066, Lines 5-15;

a. Are the aggregated variances divided among the different rate classes or just summed together?
b. If they are summed together in step 1, please explain why.
c. Please estimate the variance amounts for each class using your illustrative example.
d. Provide all necessary data and live excel spreadsheets.

RESPONSE:

a. The Company's proposal is to sum the monthly variances across all rate classes.
b. The Company's proposal is to sum the monthly variances across all rate classes and then allocate the aggregate variance to each rate class based on the proportion of authorized revenues in the most recent rate case, including step adjustments. There are three reasons the Company proposes this approach.
    - First, the proposed approach results in a consistent direction of revenue adjustments (i.e., increases or decreases in class revenues) across rate classes, avoiding a situation where some rate classes experience a rate increase while other classes experience a rate decrease.
    - Second, the proposed approach results in a consistent magnitude of revenue adjustment (i.e., percentage change in class revenues) across rate classes, avoiding a situation where some rate classes experience a significant percentage change while other classes experience a minimal percentage change.
    - Third, the proposed approach results in a more simplified process to administer and communicate since all rate classes experience similar results.
c. Please refer to OCA TS 1-04 Attachment 1. Please note the $ per therm charges are consistent with those in the filing because the Company assumed in the illustrative example that variations between actual and authorized customers and revenue per customer are the same for all rate classes. To the extent the variations are different, then the $ per therm charges will be different than what is assumed in the filing.

Northern Utilities, Inc.
Docket No. DG 21-104
OCA Data Requests – Tech Session Set 1

Date Request Received: 1/27/22 | Date of Response: 2/10/22
Request No. OCA TS 1-4 | Witness: Timothy S. Lyons

d. Please refer to OCA TS 1-04 Attachment 1

Northern Utilities, Inc.
Docket No. DG 21-104
OCA Data Requests – Tech Session Set 2

Date Request Received: 3/2/22 | Date of Response: 3/11/22
Request No. OCA TS 2-3 | Witness: Timothy Lyons

REQUEST:

Refer to Lyons Testimony, Exhibit TSL-1, Bates 1065: lines 11-14, and answer the following:

a. Please explain how the Company's proposed RDM is generally consistent with the revenue decoupling mechanism approved for the Liberty Utilities and the mechanism recently filed by the Company's New Hampshire electric division.
b. How is the Company's proposal different than the Commission approved decoupling mechanism for Liberty Utilities?
c. How is the Company's proposal different than the mechanism proposed in Docket DE 21-030.

RESPONSE:

a. Please refer to Table 1 (below).
b. Please refer to Table 1 (below).
c. Please refer to Table 1 (below).

Northern Utilities, Inc.
Docket No. DG 21-104
OCA Data Requests – Tech Session Set 2

Date Request Received: 3/2/22 | Date of Response: 3/11/22
Request No. OCA TS 2-3 | Witness: Timothy Lyons

Table 1: Key Features of Revenue Decoupling

Key Features of Revenue Decoupling	Unitil Docket No. DG 21-104	Liberty Utilities Electric Division	Liberty Utilities Gas Division	Unitil Docket No. DE 21-030
Decoupling adjustment based on "Per Customer" revenues	Yes	Yes	Yes	Yes
Benchmark "Per Customer" revenues based on authorized base revenues	Yes	Yes	Yes	Yes
Decoupling adjustment applies to residential and commercial tariff rate classes	Yes[1]	Yes[2]	Yes[3]	Yes[4]
Deferred account records variances between actual and authorized revenues per customer	Yes	Yes	Yes	Yes
Carrying costs at prime rate applied to positive and negative deferred balances	Yes	Yes	Yes	Yes
Decoupling adjustment allocated to each applicable rate class based on authorized revenues	Yes	Yes	No[5]	Yes[6]
Revenue decoupling factor calculated annually	Yes	Yes	Yes	Yes
Adjustment cap based on total revenues	Yes	No[7]	No[8]	Yes[9]

[1] Excludes special contracts.
[2] Excludes electric lighting and vehicle rate classes.
[3] Excludes special contracts.
[4] Excludes electric lighting and vehicle rate classes.
[5] The revenue decoupling adjustment is calculated separately for Residential and C&I rate classes.
[6] As filed (Settlement Agreement: requires individual rate class grouping reconciliations)
[7] Adjustment cap is equal to 3.00 percent of allowed revenue requirement
[8] There is none.
[9] As filed (Settlement Agreement: cap based on distribution revenues)

Northern Utilities, Inc.
Docket No. DG 21-104
Department of Energy Data Requests – Set 1

Date Request Received: 09/10/21 Date of Response: 09/14/21
Request No. Energy 1-11 Witness: C. Goulding / D. Nawazeski

REQUEST:

Energy 1-11

Please recalculate the Temporary Rate Revenue Deficiency making 3 adjustments to the Company's proposal:

a. Use capital structure balances as of test year end (12/31/2020).
b. Use test year property taxes
c. Use test year depreciation

RESPONSE:

Please refer to Energy 1-11 Attachment 1 for the temporary rate revenue requirement model incorporating the three requested adjustments. The Company has also corrected for the inadvertent error described in Energy 1-6.

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
OPERATING INCOME STATEMENT
12 MONTHS ENDED DECEMBER 31, 2020

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
			LESS						
LINE NO.	DESCRIPTION	TEST YEAR 12 MONTHS ENDED 12/31/2020	COST OF GAS EXCLUDING PROD. & OH.(1)	OTHER FLOWTHROUGH(2)	TEST YEAR DISTRIBUTION, PROD. & OH.	TEST YEAR DISTRIBUTION	TEST YEAR PROD. & OH.	CALENDAR YEAR 2019(3)	CALENDAR YEAR 2018(3)
	Operating Revenues:								
1	Total Sales	$ 65,455,125	$ 22,701,750	$ 3,458,228	$ 39,295,147	$ 38,237,257	$ 1,057,890	$ 72,009,468	$ 78,261,307
2	Total Other Operating Revenues	1,228,348	120,656	-	1,107,692	1,107,692	-	841,893	380,541
3	Total Operating Revenues	$ 66,683,473	$ 22,822,406	$ 3,458,228	$ 40,402,839	$ 39,344,949	$ 1,057,890	$ 72,851,361	$ 78,641,848
	Operating Expenses:								
4	Production	$ 23,544,860	$ 22,696,215	$ 398,908	$ 449,736	$ 449,736	$ -	$ 28,226,731	$ 36,699,896
5	Transmission	63,829	-	-	63,829	63,829	-	72,713	54,452
6	Distribution	3,733,377	-	-	3,733,377	3,733,377	-	3,509,448	3,547,813
7	Customer Accounting	2,608,189	99,544	-	2,508,645	2,508,645	-	2,768,758	2,548,545
8	Customer Service	2,341,706	(0)	2,268,632	73,074	73,074	-	2,319,375	1,946,672
9	Sales Expense	69,178	-	-	69,178	69,178	-	64,467	62,224
10	Administrative & General	6,740,777	-	58,225	6,682,552	6,682,552	-	7,679,291	7,670,327
11	Depreciation	8,876,582	-	-	8,876,582	8,876,582	-	8,166,463	7,482,080
12	Amortizations	816,977	-	-	816,977	816,977	-	838,480	196,816
13	Taxes Other Than Income	4,867,774	-	-	4,867,774	4,867,774	-	4,306,298	4,242,098
14	Federal Income Tax	(30,211)	-	-	(30,211)	(30,211)	-	52,380	(353,526)
15	State Income Tax	(384,644)	-	-	(384,644)	(384,644)	-	(309,547)	(463,245)
16	Deferred Federal & State Income Taxes	2,600,179	-	-	2,600,179	2,600,179	-	2,975,683	3,341,111
17	Interest on Customer Deposits	9,258	-	-	9,258	9,258	-	14,374	18,486
18	Total Operating Expenses	$ 55,857,829	$ 22,795,759	$ 2,725,765	$ 30,336,305	$ 30,336,305	$ -	$ 60,684,915	$ 66,993,749
19	Net Operating Income	$ 10,825,644	$ 26,647	$ 732,463	$ 10,066,533	$ 9,008,643	$ 1,057,890	$ 12,166,447	$ 11,648,100

Notes
(1) Refer to Workpaper - Cost of Gas
(2) Refer to Workpaper - Flowthrough Detail. Consists of Energy Efficiency, Environmental Response Costs, Residential Low Income Assistance, Rate Case Costs, Recoupment, Lost Revenue, and On Bill Financing
(3) Calendar Years 2019 and 2018 represents Total Company (i.e., Flowthrough and Distribution).