BEFORE THE
PUBLIC UTILITIES COMMISSION
OF NEW HAMPSHIRE

UNITIL ENERGY SYSTEMS, INC.	)	
REQUEST FOR CHANGE IN RATES	)	**Docket DE 21-030**

Direct Testimony of
Melissa Whited and Ben Havumaki

On Behalf of
The Office of Consumer Advocate

November 23, 2021

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I. INTRODUCTION AND QUALIFICATIONS

Q Please state your name, title, and employer.

A Ms. Whited: My name is Melissa Whited. I am a Principal Associate at Synapse Energy Economics ("Synapse"), located at 485 Massachusetts Avenue, Cambridge, MA 02139.

A Mr. Havumaki: My name is Ben Havumaki. I am a Senior Associate at Synapse Energy Economics, located at 485 Massachusetts Avenue, Cambridge, MA 02139.

Q Please describe Synapse Energy Economics.

A Synapse is a research and consulting firm specializing in electricity and gas industry regulation, planning, and analysis. Our work covers a range of issues, including economic and technical assessments of demand-side and supply-side energy resources; energy efficiency policies and programs; integrated resource planning; electricity market modeling and assessment; renewable resource technologies and policies; and climate change strategies. Synapse works for a wide range of clients, including attorneys general, offices of consumer advocates, public utility commissions, environmental advocates, the U.S. Environmental Protection Agency, U.S. Department of Energy, U.S. Department of Justice, the Federal Trade Commission, and the National Association of Regulatory Utility Commissioners. Synapse has over 30 professional staff with extensive experience in the electricity industry.

Q Please summarize your professional and educational experience.

A Ms. Whited: I have 12 years of experience in economic research and consulting. At Synapse, I have worked extensively on issues related to utility regulatory models, performance incentive mechanisms, and rate design. In 2015, I was the lead author of a report for the Western Interstate Energy Board titled "Utility Performance Incentive Mechanisms: A Handbook for Regulators," and I have presented on performance incentive mechanisms to the National Association of Regulatory Utility Commissioners, National Governor's Association Learning Lab on New Utility Business Models, Midwest Governors' Association, and the Minnesota e21 Initiative working group.

I have sponsored testimony before the Newfoundland and Labrador Board of Commissioners of Public Utilities, the Georgia Public Service Commission, the Rhode Island Public Utilities Commission, the Public Service Commission of Maryland, the Massachusetts Department of Public Utilities, the Maine Public Utilities Commission, the California Public Utilities Commission, the Hawaii Public Utilities Commission, the Public Service Commission of Utah, the Public Utility Commission of Texas, the Virginia State Corporation Commission, and the Federal Energy Regulatory Commission. I hold a Master of Arts in Agricultural and Applied Economics and a Master of Science in Environment and Resources, both from the University of Wisconsin-Madison. My resume is attached as Schedule MWBH-1.

A **Mr. Havumaki:** I have five years of experience in the energy field. At Synapse, I focus on ratemaking, rate design, performance-based regulation, and related regulatory issues. I am also regularly engaged in macroeconomic modeling and benefit-cost analysis (BCA). Prior to being hired by Synapse, I worked for the World Bank on a consulting team that authored a field manual on cost-benefit analysis for practitioners in the developing world.

I have sponsored testimony before the Georgia Public Service Commission and the Rhode Island Public Utilities Commission. I hold a Master of Arts in Applied Economics from the University of Massachusetts. My resume is attached as Schedule MWBH-2.

Q On whose behalf are you testifying in this case?

A We are testifying on behalf of the Office of the Consumer Advocate (OCA).

Q What is the purpose of your testimony?

A The purpose of our testimony is to address certain aspects of the rate application of Unitil Energy Systems, Inc. ("UES" or the "Company"). Specifically, our testimony addresses the Company's proposed multi-year rate plan, grid modernization proposal, overall rate increase for the residential class, allocation of costs among the rate classes, increase to the residential customer charge, and revenue decoupling mechanism. We do not address all aspects of the Company's proposal; silence on any issue should not necessarily be taken as acceptance of the Company's proposals.

Q What materials did you rely on to develop your testimony?

A The sources for our testimony and exhibits are public documents, responses to discovery requests, and our personal knowledge and experience.

Q Was your testimony prepared by you or under your direction?

A Yes. Our testimony was prepared by us or under our direct supervision and control.

II. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Q Please summarize your main conclusions.

A Our conclusions are as follows:

- The Company's proposal to increase residential distribution rates by 30 percent would result in rate shock and violates the principle of gradualism. This is particularly true considering the recent increase to supply rates.

- The Company's proposal for a multi-year rate plan with annual step adjustments based on net additions to rate base is devoid of any meaningful cost control incentives or performance commitments to ratepayers. The step adjustments could result in annual distribution rate increases of more than 10 percent on top of the Company's initial distribution rate increase of 30 percent for residential customers. Such increases are unreasonable.

- The Company should not rely on the minimum system method for cost allocation or as a guide for rate design. The minimum system method is deeply flawed in both theory and application and results in the overallocation of costs to the residential class and unreasonably high customer charges.

- The Company's proposal to increase the residential customer charge by nearly $5.00 fails to comport with widely accepted rate design principles, would adversely impact many low-income customers, and runs counter to state policy aims related to energy efficiency and conservation. Moreover, the proposal is based on the minimum system method, which should be rejected.

- The Company's proposed decoupling mechanism is generally sound but should be modified to provide greater customer protections.

- The Company's proposed grid modernization investments should first be addressed in the context of a Least Cost Integrated Resource Plan, consistent with RSA 378:38, and should not be approved in this docket.

Q Please summarize your recommendations.

A We offer the following recommendations:

1. The Commission should limit distribution rate increases for any one class to 125 percent of the total system rate increase.
2. The Commission should reject the Company's proposed annual step adjustments and return to traditional ratemaking. If the Company wishes for the Commission to consider alternative ratemaking, it should file a comprehensive performance-based regulation proposal that includes cost containment incentives, tracking metrics, and a commitment to improve performance in key areas through performance incentive mechanisms.
3. The Commission should reject the use of the minimum system method for cost allocation and rate design. Instead, the Company should be required to use the basic customer method for determining customer-related costs.
4. The customer charge for the domestic schedule should be maintained at its current level of $16.22 per month.
5. The Company's proposed decoupling mechanism should be approved, but with a cap on annual upward adjustments of 2.5 percent of distribution revenues, rather than total operating revenues, in order to guard against rate volatility for customers.

6. The Commission should not approve the Company's proposed grid modernization investments in this proceeding. These investments have not been adequately vetted in the context of the Company's Least Cost Integrated Resource Plan. Thus, approval of the Company's plan, and the recovery of such costs, is premature.

III. OVERVIEW OF TESTIMONY

Q Please describe the Company's proposal for revenue increases.

A The Company is proposing to increase total distribution revenues by approximately $12 million based on the calendar 2020 test year, followed by a series of step adjustments.[1] The $12 million revenue increase would represent a total distribution revenue increase of nearly 21 percent,[2] and the annual step adjustments could potentially result in year-over-year distribution revenue increases of another 10 percent or more each year.[3]

To implement this rate increase, the Company is proposing to allocate the majority of additional costs to the residential class. Specifically, the Company proposes to increase residential distribution rates by 145 percent of the system average increase,[4] yielding a 30

[1] Testimony of Robert B. Hevert, Docket No. DE 21-030, Exhibit RBH-1, April 2, 2021, p. 32.

[2] Response to OCA 3-01, Attachment 1 (Attachment MWBH-1).

[3] The Company proposes a cap on annual step adjustments of 2.5 percent of total electric operating revenue for the previous year. In 2020, the Company's total electric operating revenue was $188 million (Schedule CGDN-2, line 17), of which only $58 million was distribution revenue (Schedule RevReq-2, page 1). Thus, a 2.5 percent cap based on 2020 total revenues translates to an 8 percent increase in 2020 distribution revenues. However, default energy service rates have recently more than doubled, meaning that the Company's proposed cap based on total revenues would be higher still for future years.

[4] Schedule RJA-3, Page 1.

percent increase in residential distribution rates in the first year, followed by subsequent rate increases with each step adjustment.

Q What factors are driving the Company's overall revenue request and its proposal to increase residential distribution rates by 30 percent in the first year?

A There are several factors driving the Company's residential rate increase proposal, the primary ones being:

1) Substantial unrecovered capital investment costs;[5]
2) Future capital investments to maintain and modernize the electric distribution system;[6] and
3) The application of the minimum system method.

Q What steps should the Commission take to address these contributing factors?

A Rate cases provide the Commission with an opportunity to carefully review the reasonableness of the Company's test year revenue requirement, which is addressed by other witnesses in this proceeding. Even more importantly, rate cases provide an opportunity to assess how well the regulatory framework is operating, particularly with respect to how the incentives provided by the framework impact the Company's incentive to undertake capital investments, which is a primary focus of our testimony. In the sections below, we describe how the utility's proposed step adjustments are devoid of

[5] Testimony of Robert B. Hevert, Docket No. DE 21-030, Exhibit RBH-1, April 2, 2021, page 22.

[6] *Ibid.*

meaningful incentives to reduce costs and are therefore likely to result in over-investment and a continuation of rapidly rising rates.

In addition to addressing the overall regulatory framework, we also address inter-class equity in cost allocation. Because the minimum system method results in inequitable cost increases for the residential class, we recommend that the Commission require the Company to discontinue use of this method and instead adopt the basic customer method for classifying costs. This finding is also important in our conclusion that the proposed customer charge increase is unjustified, although there are also many policy grounds on which to reject the Company's proposed customer charge. Finally, we find the Company's decoupling proposal to be generally reasonable, as long as it is modified to provide greater customer protections against large bill swings.

IV. THE COMPANY'S REQUESTED REVENUE INCREASE WOULD RESULT IN RATE SHOCK

Q Is a 30 percent increase to residential distribution rates reasonable?

A No, the Company's proposal is flawed for numerous reasons,[7] but especially because a 30 percent distribution rate increase would contravene widely accepted ratemaking principles by subjecting residential ratepayers to rate shock. The rate shock would be

[7] As discussed below, we have numerous concerns with the Company's overall proposal, including its cost allocation study, which suggests that the residential class should be allocated an even greater rate increase. However, regardless of the results of any cost allocation studies, a 30 percent increase should be rejected on policy grounds.

particularly severe when coupled with the newly approved default energy service charges, which have more than doubled from $0.07/kWh to $0.18/kWh.[8]

Q **What ratemaking principles should be considered when setting rates?**

A We recommend that the core principles advanced by Professor James Bonbright be considered when setting rates. In his seminal work, Principles of Public Utility Rates, Professor Bonbright discusses the following eight key criteria:

1. The related, "practical" attributes of simplicity, understandability, public acceptability, and feasibility of application.
2. Freedom from controversies as to proper interpretation.
3. Effectiveness in yielding total revenue requirements under the fair-return standard.
4. Revenue stability from year to year.
5. Stability of the rates themselves, with minimum of unexpected changes seriously adverse to existing customers.
6. Fairness of the specific rates in the appointment of total costs of service among the different customers.
7. Avoidance of "undue discrimination" in rate relationships.
8. Efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use:
    a. in the control of the total amounts of service supplied by the Company;
    b. in the control of the relative uses of alternative types of service.[9]

[8] UES Default Service Compliance Tariff, Redlined, filed on October 21, 2021, available at https://www.puc.nh.gov/Regulatory/Docketbk/2021/21-041/LETTERS-MEMOS-TARIFFS/21-041_2021-10-20_UES_COMPLIANCE-TARIFF-REDLINE.PDF; and Public Utilities Commission, DE 21-041, Order Approving Default Service Rates, Order No. 26,532, October 8, 2021, available at https://www.puc.nh.gov/Regulatory/Orders/2021Orders/26-532.pdf.

[9] James Bonbright, *Principles of Public Utility Rates*, Columbia University Press, 1961, page 291.

Q Are these principles widely recognized and used by commissions?

A Yes. The principles listed above have been recognized for many years as the standard for rate design by commissions across the country. The Company also acknowledges the central role of these principles when it refers to the Bonbright's "widely-referenced treatise on utility ratemaking."[10]

Q In what way would a 30 percent increase in residential distribution rates violate Bonbright's principles?

A Bonbright's principle regarding rate stability, or gradualism, means that customer rates should not change suddenly, particularly if this will cause harm to customers by significantly increasing a customer's bill. A 30 percent increase in distribution rates coupled with a 60 percent increase in supply rates clearly violates the principle of gradualism and would result in rate shock. Large increases in customer bills will impose financial hardship on many customers, particularly low-income customers.

Q How should the Company's cost allocation proposal be modified to be consistent with the principle of gradualism?

A To comport with the principle of gradualism, we recommend that no rate class be subject to a rate increase exceeding 125 percent of the system average increase. In addition, we recommend that the Commission seek to strengthen the utility's cost containment incentives so that the Company is encouraged to operate as efficiently as possible and future rate increases are more limited. The Company's proposed step adjustments do not provide such cost containment incentives, as discussed below.

[10] Direct Testimony of John D. Taylor, Docket No. DE 21-030, Exhibit JDT-1, April 2, 2021 at 4.

I. THE COMPANY'S MULTI-YEAR RATE PLAN PROVIDES INSUFFICIENT COST CONTAINMENT INCENTIVES

Q Please describe the Company's proposed multi-year rate plan.

A Company witnesses Messrs. Goulding and Nawazelski testify that the Company is proposing a "multi-year rate plan with annual step adjustments to recover the revenue requirement of capital additions to rate base."[11] Under this rate plan, the Company would make a filing in January of each year to account for the prior year's net change in non-growth plant additions, and rate adjustments would go into effect on April 1.[12]

Q Does the Company's proposal resemble a typical multi-year rate plan?

A Not at all. What the Company has proposed is essentially a series of annual rate cases that address rate base adjustments and associated revenue requirements. Unlike typical multi-year rate plans, the Company's proposal essentially removes regulatory lag from the traditional ratemaking process without introducing new cost containment incentives to encourage the utility to operate efficiently. This represents a significant departure from traditional ratemaking and shifts the balance of risk toward customers while undermining the utility's cost control incentives. In contrast, most multi-year rate plans seek to strengthen cost containment incentives by capping the utility's allowed revenues at a meaningful level and providing financial incentives for reducing costs below the cap.

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[11] Testimony of Goulding and Nawazelski, Docket No. DE 21-030, Exhibit CGDN-1, April 2, 2021, page 37.

[12] Schedule CGDN-1, page 1 (Bates 000199).

Q What mechanisms do multi-year rate plans typically employ to provide cost containment incentives?

A Cost containment incentives in multi-year rate plans are the product of multiple factors. First, annual revenue adjustments are decoupled from the utility's actual costs. The revenue adjustments[13] provide "a utility an *allowance* for cost growth rather than reimbursement for its *actual* [cost] growth."[14] Thus, there is no true-up to actual costs during the rate plan.

Because there are no true-ups to actual costs during the rate plan, the utility must live within its revenue allowance. If the utility reduces its costs during the rate plan, it is frequently allowed to retain some or all of the savings. Conversely, if the utility exceeds its allowed revenue requirement, it must absorb some or all of these excess costs.[15] This shifts both the risk and reward associated with utility cost management to utility management and shareholders, rather than ratepayers, which strengthens the utility's cost containment incentives.[16]

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[13] These revenue adjustments during the rate plan period may be based on an external cost index (such as inflation), cost forecasts, or a combination of the two. If utility cost forecasts are used, care must be taken to ensure that the forecasts are reasonable and in the public interest, increasing the need for regulatory oversight and information transparency.

[14] Mark N. Lowry, Matthew Makos, and Gretchen Waschbusch, "Alternative Regulation for Emerging Utility Challenges: 2015 Update" (Edison Electric Institute, November 11, 2015), 34.

[15] Earnings sharing mechanisms are a common component of multi-year rate plans and determine the extent to which the utility can keep any savings. Earnings above a certain threshold are often shared with customers. In rare cases, utility under-earnings may also be shared with customers. Of 19 utilities in the United States with earnings sharing mechanisms, only one is reported to have a symmetrical earnings sharing mechanism. The others share over-earnings only. Mark N. Lowry, Matthew Makos, and Gretchen Waschbusch. *Alternative Regulation for Emerging Utility Challenges: 2015 Update*. Edison Electric Institute. November 11, 2015, page 37-38.

[16] However, as discussed later, when the utility's allowed revenues for capital investments are based on capital cost forecasts rather than external indexes, jurisdictions often require the utility to return any under-spend to ratepayers.

Finally, a multi-year rate plan institutes a "stay-out period" often lasting from three to five years. This stay-out period ensures that the utility cannot simply come in for a new rate case if costs and revenues diverge, thereby strengthening the cost containment incentives associated with the revenue cap.

Q Does the Company's proposal provide greater cost containment incentives than traditional cost-of-service regulation?

A No. Traditional cost-of-service regulation creates an inherent cost containment incentive by setting rates based on a test year and then holding those rates fixed[17] until the utility files another rate case. Assuming that sales remain the same each year, the utility can increase profits by reducing costs during the period between rate cases, since the utility generally keeps any difference between revenues and costs. On the other hand, if costs increase under cost-of-service regulation, the utility's profits will decline until the higher costs are reflected in rates in a subsequent rate case. This delay in reflecting new costs in rates is referred to as "regulatory lag," and it helps incentivize efficient utility operations.[18]

The Company's rate plan removes most of the regulatory lag associated with cost-of-service regulation by introducing annual "step adjustments." Although technically these step adjustments are subject to a cap, the cap proposed by the Company is so high as to provide very little incentive to control costs. Further, the proposal would allow the

[17] With the exception of certain cost trackers that adjust rates as costs change.

[18] Of course, under cost-of-service regulation, the utility can always file a rate case when costs exceed revenues, thereby blunting its cost containment incentives.

Company to defer costs exceeding the cap to the next rate case at the Company's cost of capital, which compensates the utility for any delay in revenue recovery, thereby gutting any remaining cost containment incentives from the rate plan.[19]

While the Company's proposal provides the utility with virtually no downside for increasing spending, it also provides the utility with no upside for reducing spending, as the revenue increase in the annual step adjustments is based on actual costs. Thus, any cost efficiencies are returned to ratepayers, eliminating incentives for the utility to seek innovative solutions that would reduce costs below allowed revenue requirements.

Q Why do you assert that the Company's proposed cap on revenue adjustments does not provide adequate cost containment incentives?

A The Company proposes that adjustments be limited to 2.5 percent of the Company's prior year total electric operating revenue, with revenue for externally supplied customers being adjusted by imputing the Company's default energy service charges for that period.[20] In other words, the cap would be based on the Company's operating revenues including all supply costs, even for customers who take service from a retail supplier. In 2020, the Company calculated its total electric operating revenue for the purposes of the rate cap as $188 million.[21] Of this amount, only 31 percent ($58 million) was distribution revenue.[22] Thus, a 2.5 percent cap based on 2020 total revenues translates to an 8 percent increase in 2020 distribution revenues. However, default energy service rates have

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[19] Schedule CGDN-1, page 2 (Bates 000200).

[20] Schedule CGDN-1, page 2 (Bates 000200).

[21] Schedule CGDN-2, line 17.

[22] Schedule RevReq-2, page 1.

recently more than doubled, meaning that the Company's proposed cap based on total revenues could be even higher still for future years. Thus, the Company's proposal could easily lead to distribution revenue increases of 10 percent or more each year, which would provide negligible incentives for the utility to control its spending and result in unreasonable rate increases for customers.

Q Would a lower cap on revenue adjustments mitigate your concerns?

A A cap set much lower based on distribution revenues only or a fixed amount (rather than fluctuating with supply costs) would represent an improvement over the Company's proposal. However, the plan would still suffer from serious design flaws in that the revenue adjustments would still be based on the Company's actual spending, which limits the Company's incentives to innovate to develop more efficient ways of providing service, since the Company will not benefit from such efficiencies.

Q Does the Company's stay-out provision provide an incentive for the Company to reduce costs?

A No. The Company has proposed a stay-out provision in which it would not come in for another rate case until the end of 2024, but because the rest of the rate plan lacks meaningful cost containment incentives, the stay-out provision is largely an empty gesture.

Q Are you proposing that the Commission adopt a multi-year rate plan that reflects the components you just described?

A For the purposes of this rate case, we recommend that the Commission reject the Company's proposed step adjustments and return to traditional cost-of-service regulation. If the Company wishes to pursue a multi-year rate plan in the future, the Company should do so in the context of a comprehensive performance-based regulation proposal, consisting of a multi-year rate plan with a meaningful cap on annual revenue adjustments (ideally set based on an external index),[23] an earnings sharing mechanism, and a stay-out period; as well as performance incentive mechanisms.

Q Please explain what you mean by a "comprehensive performance-based regulation framework."

A Performance-based regulation includes both performance incentive mechanisms and multi-year rate plans. Historically, performance incentive mechanisms were implemented primarily to ensure that the cost-cutting pressures from a multi-year rate plan did not result in degradation of utility service quality. Thus, traditional performance incentive mechanisms generally focused on reliability (SAIDI, SAIFI, and CAIDI) and customer service (e.g., call center responsiveness). More recently, performance incentive mechanisms have also been implemented to better align utility incentives with state energy policy goals, such as empowering customers and accommodating distributed energy resources.

A combination of performance incentive mechanisms and a well-designed multi-year rate plan would improve the likelihood that both the utility and customers will benefit from the modified regulatory framework. Without all of these elements, customers are better served under traditional cost-of-service regulation.

[23] Ideally, the annual revenue adjustments should be tied to an external inflation index, rather than based on utility cost forecasts. If forecasts are used, they should be tied directly to the investments contained in the utility's Least Cost Integrated Resource Plan and thoroughly vetted by stakeholders first.

II. THE COMPANY'S COST ALLOCATION METHODOLOGY IS FLAWED

Q Do you have any concerns regarding the Company's cost allocation method?

A Yes. Our primary concern hinges upon the use of the minimum system method for classifying costs as demand-related or customer-related. The minimum system method classifies costs by estimating the cost of building from scratch a hypothetical system employing the smallest size components typically installed, and then deeming those costs customer-related. This inevitably causes too great a portion of costs to be so classified, in a manner that is theoretically flawed and inequitable.

Q Why do you maintain that the minimum system method is flawed and inequitable?

A The shortcomings of this method have been widely documented. For example, multiple pages in the Regulatory Assistance Project's 2020 manual *Electric Cost Allocation for a New Era* are devoted to examining the flaws of the minimum system method. The relevant pages from the manual are included as Attachment MWBH-2, and key critiques of the minimum system method from the RAP manual are summarized below:[24]

1) The hypothetical "minimum system," used as the basis for this cost allocation method, still has the ability to serve some load—often a large portion of a typical residential customer's load. Without correcting for this, the minimum system overstates the customer-related costs.

[24] Jim Lazar, Paul Chernick, and William Marcus, "Electric Cost Allocation for a New Era: A Manual" (Regulatory Assistance Project, 2020), 145–49, https://www.raponline.org/wp-content/uploads/2020/01/rap-lazar-chernick-marcus-lebel-electric-cost-allocation-new-era-2020-january.pdf.

2) A large portion of the cost of the distribution system (e.g., the number of poles and length of conductors) is driven by the size of the territory served, rather than the number of customers.

3) The minimum system method generally uses commonly installed minimum sizes, rather than the smallest equipment ever used, currently in use, or that could be used. However, a key reason for using larger equipment is due to higher customer demands, and thus the minimum size currently in use does not represent the true minimum that would be required for a hypothetical minimum system.

4) The hypothetical minimum system is assumed to have the same number of units (number of poles, feet of conductors, etc.) as the actual system. In reality, both the size of equipment and the number of units is often driven in part by load.

5) Increasing the number of customers in an area without increasing demand can be accomplished with no additional poles or conductors.

The manual concludes that the "minimum system analysis does not provide a reliable basis for classifying distribution investment and vastly overstates the portion of distribution that is customer-related."[25]

[25] Lazar, Chernick, and Marcus, 146.

Q Do you have any additional concerns with the minimum system method as applied by the Company?

A Yes. In addition to the numerous theoretical flaws inherent in the minimum system method, the Company did not apply the method in a manner consistent with the 1992 NARUC *Electric Utility Cost Allocation Manual*.[26] Instead of using the book cost associated with distribution system components, the Company escalated the costs of the hypothetical minimum system to 2020 dollars according to the Handy Whitman index. The Company then computed the share of customer-related costs as a percentage of the total revenue requirement for that portion of the distribution system. However, since the remainder of the revenue requirement was *not* escalated to 2020 dollars, the Company's method significantly overstates the portion of costs that should be classified as customer-related under the minimum system method.

Q Why is it problematic to escalate the minimum system costs without escalating the rest of the costs in the revenue requirement?

A The Company's approach is problematic because it does not compare cost categories on an apples-to-apples basis. Instead, costs classified as customer-related are escalated to 2020 dollars, while the remaining costs in the utility's revenue requirement are not.

Q How large of an impact does using 2020 dollars for minimum system costs have on the allocation of revenues to the residential class?

A We estimate that the costs allocated to the residential class are overstated by 32 percent due to escalating the minimum system costs to 2020 dollars. We calculated this by using

[26] NARUC, *Electric Utility Cost Allocation Manual* (Washington, DC: National Association of Regulatory Utility Commissioners, 1992).

the accumulated costs in the Company's minimum system workpaper,[27] rather than those same costs multiplied by the escalation factor from the Handy-Whitman index.[28] This resulted in a much smaller portion of costs in each distribution account being classified as customer-related. The difference in the proportion of costs classified as customer-related are summarized in the table below. For example, the portion of Account 364 (poles, towers, and fixtures) classified as customer-related falls from 45 percent to 13 percent for the primary system and from 46 percent to 13 percent for the secondary system.

Table 1. Portion of costs classified as customer-related using escalated and non-escalated costs

		Primary		Secondary	
Acct	Description	Escalated to 2020$	No Escalation	Escalated to 2020$	No Escalation
364	Poles, towers, & fixtures	45%	13%	46%	13%
365	Overhead conductors & devices	51%	12%	71%	12%
367	Underground conductors	69%	29%	36%	13%
368	Transformers	N/A	N/A	54%	18%

Q What method do you recommend using instead of the minimum system?

A We recommend using the basic customer method. Under this method, only the meter, service drop, and billing/collection costs would generally be classified as customer-related.

Q Why do you recommend the basic customer method instead of the minimum system method?

A The basic customer method adopts Bonbright's definition of customer-related costs as the "costs found to vary with the number of customers regardless, or almost regardless, of

[27] Provided in response to Staff 2-30, Attachment 4

[28] The accumulated costs are provided in the workpaper in sheet "Acct 364 to 368 vintage qty" column E.

power consumption."[29] As stated by the RAP manual, the "basic customer method for classification is by far the most equitable solution for the vast majority of utilities."[30] The manual notes that the basic customer method is currently used by jurisdictions across the country, including Arkansas, California, Colorado, Illinois, Iowa, Massachusetts, Texas, and Washington.[31]

III. THE COMPANY'S PROPOSAL TO INCREASE RESIDENTIAL CUSTOMER CHARGE SHOULD BE REJECTED

Q Please describe the Company's proposed increase to the residential customer charge.

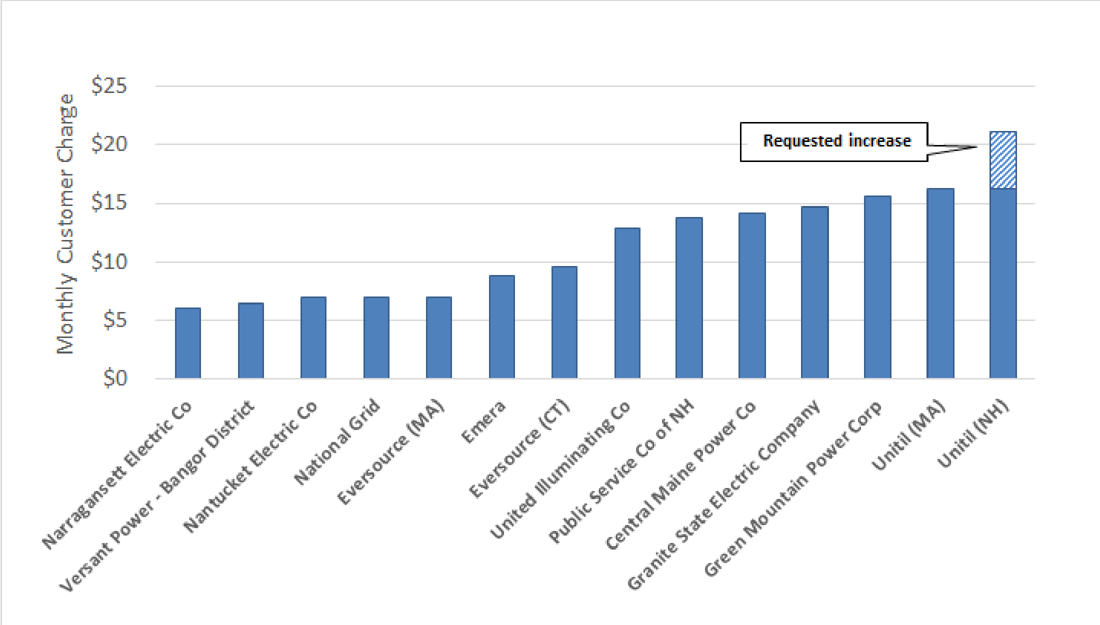
A The Company proposes to increase the residential customer charge by nearly $5.00—from $16.22 per month to $21.07 per month. We note that the Company's current customer charge of $16.22 is already the highest in New England. If the Company's proposed increase in the customer charge were to be granted, it would make its domestic rate a true outlier among its peers. We compare the Company's customer charge and the proposed increase to those of its peers in New England in Figure 1, below.

[29] James Bonbright, *Principles of Public Utility Rates* (New York: Columbia University Press, 1961), 347.

[30] Lazar, Chernick, and Marcus, "Electric Cost Allocation for a New Era: A Manual," 145.

[31] Lazar, Chernick, and Marcus, 145.

Figure 1. Monthly Customer Charges for Investor-owned Utilities in New England[32]



Q Other than being out of step with other utilities in the region, is the proposed increase to the residential customer charge reasonable?

A No, for several reasons. First, the proposed increase to the customer charge is based on the flawed minimum system method, as discussed above. Second, the increase is inconsistent with the principle of gradualism. Third, the increase would undermine public policy goals.

Q Please explain how the Company's proposed increase to the customer charge would violate the principle of gradualism.

A If the currently proposed increase were to be granted, the result would be a customer charge that has increased by approximately 150 percent since 2011, from $8.40 per month to $20.07 per month. Moreover, the proposed increase in the customer charge

[32] Customer charge data for New England utilities sourced from utility tariffs.

would alter the rate structure of the domestic schedule by continuing the trend toward an increasingly fixed overall bill.

Q Is the proposed increase to the customer charge consistent with cost causation?

A No. Although the Company claims that the higher customer charge would bring it closer to the actual marginal customer cost,[33] this claim is based on the flawed minimum system method. Applying the basic customer method to the Company's cost allocation model results in a monthly residential customer charge of $17.79, which is closer to the current customer charge than the Company's proposal.[34] However, it is widely recognized that rate design should not blindly adhere to cost allocation results, and there are numerous other factors that should be considered when designing rates.

Q Why should cost allocation results not be applied directly to rate design?

A The results of a cost allocation study are just one factor among many that should be considered when designing rates. It appears that the Company recognizes this point, too, as it notes that rate design, "must necessarily include the exercise of judgement, as both quantitative and qualitative information must be evaluated before reaching a final rate design determination."[35] Thus, rate design is a product of both policy considerations and cost causation analyses.

[33] Direct Testimony of John D. Taylor, Docket No. DE 21-030, April 2, 2021 at 7.

[34] To perform this calculation, all secondary distribution system components were removed from the "customer" classification in the Company's cost of service model on worksheet "Input-Allocators."

[35] NH PUC. Docket No. DE 20-030. Direct Testimony of John D. Taylor, at 5.

Q Do you recommend increasing the customer charge to $17.79 per month, as indicated by the basic customer method?

A No. We recommend maintaining the customer charge at its current level of $16.22. As noted above, cost allocation results should not be binding on rate design. In the Company's case, the customer charge for residential customers is already very high. Moreover, we have several other concerns about the impacts of another increase to this customer charge—namely that the increase would adversely impact low-income customers and undermine state policy goals related to energy efficiency, distributed generation, and customer empowerment.

Q How will the Company's rate design unfairly impact low-use customers' bills?

A The Company's proposal would place a disproportionate strain on customers that use the least energy. Low-use customers will see disproportionately large average monthly bill increases, and their bills will becoming increasingly fixed. Simply put, the lower a customer's monthly consumption, the greater the relative bill increase. This impact is clearly shown in Schedule JDT-3, the key columns of which are reproduced below in Table 2.

Table 2. Increase in total bills for residential customers by usage

Monthly kWh	Total Bill Using Rates Effective 12/1/2020	Total Bill Using Rates Proposed	Difference	% Difference
0-100	$22.71	$27.87	$5.17	22.7%
101-200	$42.79	$48.93	$6.14	14.3%
201-300	$59.78	$66.74	$6.96	11.6%
301-400	$76.89	$84.67	$7.78	10.1%
401-500	$94.06	$102.68	$8.62	9.2%
501-750	$122.87	$132.88	$10.01	8.1%
750-1,000	$165.67	$177.74	$12.08	7.3%
1,000-1,500	$223.98	$238.87	$14.90	6.7%
1,501-2,000	$311.56	$330.69	$19.13	6.1%
2,001-3,500	$439.52	$464.83	$25.32	5.8%
3,501-5,000	$711.82	$750.30	$38.48	5.4%
600	$120.00	$129.87	$9.87	8.2%

Source: Schedule JDT-3

As shown in the table above, the lowest-usage customers will see total bill increases of 14 percent or more, while the highest usage customers will see total bill increases in the range of 6 percent.

Q Who are the low-use customers that will be most impacted by the proposed rate design?

A Customers who consume less than average generally include low-income customers and customers who have taken steps to reduce their electricity consumption—often through investing personal financial resources in energy efficient technologies or distributed generation.

Q Why do you suggest that low-income customers would be hit hard by the increased basic service charge?

A Low-income customers tend to use less energy on average. This means that higher basic service charges will raise electricity bills most for those who can least afford it.

Q On what basis do you conclude that low-income customers tend to use less energy than average residential customers?

A Regional data from the Energy Information Administration's (EIA) 2015 Residential Energy Consumption Survey (RECS) for New England shows a clear positive relationship between income and annual electricity consumption, with usage generally increasing with income, and households in the two highest income tiers consuming more than double the amount of electricity as households in the lowest income tier.[36] The correlation between income and electricity consumption is also supported by data from the U.S. Department of Energy's (DOE) Low-Income Energy Affordability Data Tool (LEAD). While the LEAD tool reports spending on energy, this can be viewed as a proxy for energy consumption. For New Hampshire, LEAD shows a clear relationship between household income and total spending on both electricity and all energy, with households in the lowest income grouping (0 percent to 30 percent of state median income) reported to spend about 47 percent less on electricity per month than households at or above the median income level.[37]

Q Shouldn't the fact that lower-income households spend less on electricity alleviate concern about the impacts of increasing the customer charge?

A On the contrary, despite spending less in absolute dollars per annum on electricity, these low-income households use a far greater share of their available funds on electricity and other energy. In other words, they face far worse energy burdens (the percentage of household income spent on energy bills). Per the LEAD data, in New Hampshire,

[36] U.S. EIA. 2015 RECS Survey Data. https://www.eia.gov/consumption/residential/data/2015/.

[37] DOE. LEAD Tool. https://www.energy.gov/eere/slsc/maps/lead-tool.

households in the lowest income group have average electricity burdens of 10 percent, and average total energy burdens of about 19 percent—a strikingly high figure.[38] In contrast, households with incomes equal to at least the state median income level have average electricity burdens of 1 percent and average total energy burdens of 3 percent. The low-income customers with the highest energy burdens will be the ones experiencing the highest rate increases as a result of the increased customer charge.

Q Does New Hampshire's Low-Income Electric Assistance Program (EAP) mitigate against these negative effects?

A Only to a limited degree. First, it is important to recognize that the EAP program does not completely shield customers from the impacts of increases in the customer charge. In its present form, the program provides a discount of between 8 percent and 76 percent on the monthly customer charge, depending on household income.[39] More critically still, many eligible customers do not receive benefits from EAP.

Q How do you know that many eligible customers do not receive benefits from EAP?

A According to the Company's most recent EAP monthly report available, out of a total 67,125 residential accounts, only 7,719 accounts received assistance.[40] While we do not have access to household income data for the Company's residential customers, we are able to estimate the overall statewide eligibility share. With an income eligibility

[38] U.S. DOE. LEAD Tool. https://www.energy.gov/eere/slsc/maps/lead-tool.

[39] NH PUC. Docket No. DE 21-030. Hearing Exhibit 3 (Temporary Rates) at 3.

[40] NH PUC. Docket No. DE 20-123.Unitil Energy Systems, Inc. EAP Monthly Report, May 2021, at 5.

threshold set at 60 percent of state median income,[41] data from the American Consumer Survey suggests that at least 25 percent of all New Hampshire households should be eligible. For the Company's service territory, this finding would imply that there were greater than 9,000 households in the Company's service territory that were eligible, but not receiving EAP assistance. In other words, it would appear that most eligible households do not receive EAP assistance. These low-income households without assistance will be particularly hard hit by the Company's proposed customer charge increase.

Q What are the equity implications of your analysis?

A Our analysis shows that rate design has important equity implications by increasing bills for some types of customers more than others. Specifically, the proposed customer charge increase would have regressive impacts by increasing bills the most for customers who can least afford it.

Q Why do you contend that raising the customer charge would contravene Bonbright's principle of discouraging wasteful usage?

A By increasing the proportion of a customer's bill that is fixed and that cannot be offset by energy efficiency or other distributed resources, the Company's proposed rate design would reduce the incentive for customers to make such investments. This effect fails to meet Bonbright's eighth principle, which is discouraging wasteful use of service. It also

[41] NH Office of Strategic Initiatives. Income Eligibility Guidelines. https://www.nh.gov/osi/energy/programs/fuel-assistance/eligibility.htm.

runs counter to state policies that aim to enhance environmental protection and encourage energy efficiency. For example:

- In NH RSA 4-E:1 (the act that established the requirement for the state's 10-year energy strategy), the state articulated a commitment to "protecting natural, historic, and aesthetic resources" and specifically called for its energy strategy to consider energy efficiency and conservation.[42]

- In NH RSA 378:37, which established the Least Cost Integrated Resource Plan standard, the state enshrined both "protection of the safety and health of the citizens" and "[protection of] the physical environment of the state" as key energy policy considerations.[43]

- In NH RSA 374-F:3, X, which lists energy efficiency among the policy principles that guided the restructuring of the electric industry.[44]

Q Has the Commission addressed the relationship between customer charges and the incentive to conserve energy?

A Yes. In the Commission's Order No. 26,122 in DG 17-048, the Commission recognized the conservation benefits of revenue recovery through variable, rather than fixed charges, writing:

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[42] NH RSA 4-E:1(II).

[43] NH RSA 378:37.

[44] NH RSA 374-F:3, X.

> Because decoupling reduces the risk that the utility will not receive its expected revenue, it allows fixed charges to be reduced. It also makes variable charges, based on usage, a larger part of a customer's bill and thus encourages conservation and efficient use.[45]

While DG 17-048 concerned decoupling for gas revenues, the principle articulated by the Commission applies here—the combination of lower fixed charges and higher variable charges, all else equal, promotes conservation.

Q Have other commissions recognized the detrimental impact of higher fixed customer charges?

A Yes, the negative effects of increasing basic service charges are well-recognized. One example comes from a 2016 rate case in Maryland. While the Potomac Electric Power Company requested to increase its basic service charge for residential customers from $7.39 per month to $12.00 per month, the Maryland Public Service Commission approved a much smaller increase to only $7.60 per month and explained that the proposed change would result in customers having less control over their bills and would be antithetical to energy conservation efforts.

> In arriving at this increase, we place emphasis on Maryland's public policy goals that intend to encourage energy conservation. Maintaining relatively low customer charges provides customers with greater control over their electric bills by increasing the value of volumetric charges. No matter how diligently customers might

[45] NH PUC. Docket No. DG 17-048. Order No. 26,122, at 54.

> attempt to conserve energy or respond to AMI-enabled peak pricing incentives, they cannot reduce fixed customer charges.[46]

In 2012, the Missouri Public Service Commission rejected a proposed increase in the basic service charge for residential and small general service classes, writing:

> Shifting customer costs from variable volumetric rates, which a customer can reduce through energy efficiency efforts, to fixed customer charges, that cannot be reduced through energy efficiency efforts, will tend to reduce a customer's incentive to save electricity. Admittedly, the effect on payback periods associated with energy efficiency efforts would be small, but increasing customer charges at this time would send exactly [the] wrong message to customers that both the company and the Commission are encouraging to increase efforts to conserve electricity.[47]

Q What do you recommend regarding the residential customer charge?

A For all of the reasons discussed above, we recommend that the Commission reject the Company's proposal and retain the existing residential customer charge.

[46] MD PSC. Case No. 9418. *In The Matter of the Application of Potomac Electric Power Company for Adjustment to its Retail Rates for the Distribution of Electric Energy*, Order No. 87884, at 110.

[47] MO PSC. File No. ER-2012-0166. *In the Matter of Union Electric Company Tariff to Increase Its Annual Revenues for Electric Service*, Report and Order, at 110-11.

IV. THE COMPANY'S REVENUE DECOUPLING MECHANISM SHOULD BE APPROVED, WITH MODIFICATIONS

Q Please describe the Company's proposed revenue decoupling mechanism.

A In compliance with the Commission's Order No. 25,932, the Company is proposing a revenue decoupling mechanism (RDM) that reconciles monthly actual revenues per customer to authorized revenues per customer, by rate class. Any differences between actual and authorized revenues per customer would be aggregated over a 12-month period,[48] with revenue surpluses being refunded to customers, and revenue shortfalls recovered through a surcharge. Under the Company's proposal, the RDM would apply to all classes except the proposed electric vehicle and lighting classes.[49]

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

A Yes. The Company proposes to cap decoupling adjustments for revenue shortfalls to 2.5 percent of total revenues from delivered sales for the most recent 12-month period to "mitigate customer bill impacts."[50]

Q Do you support the Company's revenue decoupling proposal?

A In part. We wish to first acknowledge the important role that revenue decoupling plays in aligning utility incentives with the public interest. By ensuring that a utility recovers its revenue requirement even when sales decline, decoupling mitigates a utility's disincentive to support demand-side resources (including energy efficiency and other

[48] Monthly variances would be recorded in a deferred account with carrying costs accrued at the Prime rate.

[49] Direct Testimony of Timothy Lyons, Exhibit TSL-1, pages 5-6 (Bates 001459 – 001460).

[50] Lyons, Exhibit TSL-1, page 16 (Bates 001470).

distributed energy resources). Further, full decoupling is superior to a Lost Revenue Adjustment Mechanism (LRAM), since under full revenue decoupling the utility does not benefit from increasing sales, and revenue adjustments under full revenue decoupling are simpler and less contentious to calculate than under an LRAM.

In an era of declining sales per customer, revenue decoupling also reduces the need for a utility to adjust revenues through frequent rate cases, step adjustments, or multi-year rate plans. At the same time, decoupling offers a better means for addressing revenue volatility than increasing the customer charge.

Q Do you have any concerns with the Company's proposal?

A Yes. Our primary concern is that the Company's proposed cap on upward revenue decoupling adjustments is far too large to provide adequate protection for ratepayers against rate volatility.

Q Please explain your concern that the Company's cap on decoupling adjustments does not adequately protect ratepayers.

A The Company's proposed cap on revenue decoupling adjustments is set at the same level as the cap it is proposing for annual step adjustments—at 2.5 percent of the Company's operating revenues including all supply costs, even for customers who take service from a retail supplier.[51] Yet because only a small portion of the Company's total electric operating revenue is distribution revenue, a 2.5 percent cap based on 2020 total revenues translates to 8 percent of 2020 distribution revenues. Since the approved default energy service rates have

[51] Revenues for customers taking service from a competitive supplier would be calculated using the Company's default energy service charges, according to Lyons, Exhibit TSL-1, page 16 (Bates 001470).

more than doubled recently, the cap on revenue decoupling adjustments could far exceed 8 percent of distribution revenues in future years.

Q How do you recommend that the cap be set?

A As the recent adjustment to default energy service charges illustrates, supply rates can be extremely volatile. Thus, any cap on adjustments—whether for decoupling or annual step adjustments (should they be approved)—should be based on distribution revenues only, or a fixed value. Thus, we recommend that the cap on upward decoupling adjustments be set at 2.5 percent of distribution revenues.

V. THE COMPANY'S GRID MODERNIZATION PROPOSAL SHOULD FIRST BE VETTED THROUGH ITS LEAST COST INTEGRATED RESOURCE PLAN

Q What grid modernization investments are contained in the Company's proposal?

A During the years covered by the Company's proposed rate plan (2021–2023), the Company plans to undertake approximately $8.5 million in grid modernization investments, the costs of which would be recovered through annual step adjustments. However, the Company's grid modernization investments are expected to continue well into the future, with nearly $40 million being invested by 2030.[52] This spending plan is shown in the table below.

[52] Exhibit (KES-3), page 11. (Bates 000509).

Table 3. Grid Modernization Spending Plan[53]

	Project Costs (000's)										
Projects	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Field Area Network	$ 90	$ 56	$ 127	$ 626	$ 325	$ 463	$ 780	$ 811	$ 640	$ 704	$ 4,622
ADMS and DERMS	$ 668	$ 468	$ 378	$ 298	$ 170	$ -	$ -	$ -	$ -	$ -	$ 1,981
Volt/VAR Optimization	$ -	$ 383	$ 2,000	$ 2,929	$ 2,731	$ 2,862	$ 2,880	$ 3,416	$ 3,488	$ 4,292	$ 24,981
SCADA	$ -	$ 1,530	$ 1,740	$ 760	$ 790	$ 250	$ 340	$ 420	$ 550	$ 760	$ 7,140
Mobile Damage Assessment	$ 449	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 449
AMI/OMS Integration	$ 107	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 107
Data Sharing Platform	$ 449	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 449
Total	$1,763	$2,437	$4,245	$4,612	$4,016	$3,575	$4,000	$4,647	$4,678	$5,756	$ 39,729

Q What are the objectives of the Company's grid modernization proposal?

A The Company's objectives for its grid modernization plan, as discussed in its proposal, can be summarized as follows:

- Deliver safe and reliable service for today's customers and the 21st Century economy;
- Enable adoption of new technologies and services to allow customers to better manage their energy needs;
- Reduce the environmental impact of electricity by integrating all types of generation and storage, improve efficiency, and optimize demand; and
- Encourage innovation by supporting the interconnection and business models of third parties.[54]

[53] Reproduced from Exhibit (KES-3), page 11, Table 1. (Bates 000509).

[54] Grid Modernization Plan, Exhibit (KES-3), March 2021, pages 16-17 (Bates 000514-000515).

Q **Do you support the Company's grid modernization proposal?**

A While we applaud the Company's vision to modernize the grid to achieve the objectives outlined above, the Company's rate application is not the appropriate venue for introducing such investments. Instead, these investments should first be vetted through the Company's Least Cost Integrated Resource Plan (LCIRP). The least-cost planning statute specifically requires that LCIRPs include "an assessment of the benefits and costs of 'smart grid' technologies, and the institution of electric utility programs designed to ensure a more reliable and resilient grid to prevent or minimize power outages."[55] The Company's 2020 LCIRP contained only a high-level discussion of planned grid modernization investments, primarily focusing on the activities being undertaken by its Massachusetts affiliate that it plans to also implement in its New Hampshire service territory.[56] However, the plan did not include specifics regarding the timing or costs of grid modernization investments in New Hampshire, as the Company stated that its roadmap and accompanying business plan were still under development.[57]

Q **Why is it necessary to first review grid modernization proposals in the context of an LCIRP?**

A There are several reasons why the LCIRP process is the appropriate place to address grid modernization proposals. First, as evidenced by a plain reading of the statute, the legislature intended for grid modernization proposals to be developed and presented in utilities' LCIRPs.

[55] RSA 378:38.

[56] UES, Docket DE 20-002, Report on Least Cost Integrated Resource Planning 2020, March 2020, pp. 22-24.

[57] *Id.*, p. 21.

Second, an LCIRP allows for grid modernization plans to be considered in the context of all of the utility's other distribution system investments. This allows for parties to better identify how the components interact, and how investments in grid modernization technologies may impact the need for investments in traditional distribution infrastructure. As the Commission stated in its 2020 Grid Modernization order, "[a] more granular and transparent approach to distribution system planning is necessary to ensure that investments are prioritized in a manner that accommodates an evolving electric system, while also maximizing ratepayer value."[58] Moreover, the Commission stated its expectation that "investments for which recovery is requested in rate cases are consistent with investments described in the LCIRP and related filings."[59]

Finally, the Commission has repeatedly observed that "constructive stakeholder processes can aid the Commission in its decision-making duties and allow parties to reach a result in line with their expectations."[60] In contrast to a litigated rate case, an LCIRP process provides greater opportunity for parties to interact constructively and enhances transparency. It also allows parties to potentially resolve issues prior to a litigated case.

[58] Although this order was issued after the Company's 2020 LCIRP filing and is currently under suspension, it reflects substantial consensus among the parties on numerous issues. Public Utilities Commission, Order Guidance on Utility Distribution System Planning and Order Requiring Continued Investigation, Order No. 26, 358, Docket IR 15-296, May 22, 2020, at 5.

[59] Public Utilities Commission, Order Guidance on Utility Distribution System Planning and Order Requiring Continued Investigation, Order No. 26, 358, Docket IR 15-296, May 22, 2020, at 25.

[60] Public Utilities Commission, Order Approving Benefit Cost Working Group Recommendations, Order No. 26,322, Docket 17-136, December 30, 2019, at 8; and Public Utilities Commission, Order Guidance on Utility Distribution System Planning and Order Requiring Continued Investigation, Order No. 26, 358, Docket IR 15-296, May 22, 2020, at 24.

For these reasons, we recommend that the Commission decline to address the Company's grid modernization proposal in the instant proceeding and direct the Company to first introduce its proposal in the context of an LCIRP.

VI. CONCLUSION AND SUMMARY OF RECOMMENDATIONS

Q Please summarize your main conclusions and recommendations.

A Our conclusions and recommendations are as follows:

1. The Company's proposed increases to residential rates should be modified to no more than 125 percent of the system average increase in order to avoid rate shock.

2. The Company's proposal for a multi-year rate plan with annual step adjustments is devoid of any meaningful cost control incentives or performance commitments to ratepayers, and would result in unreasonable rate increases. It should thus be rejected in favor of a return to cost-of-service regulation. If the Company wishes for the Commission to consider alternative ratemaking, it should file a comprehensive performance-based regulation proposal.

3. The minimum system method is deeply flawed in both theory and application and results in the overallocation of costs to the residential class and unreasonably high customer charges. Therefore, the Commission should require the Company to use the basic customer method for determining customer-related costs.

4. The Company's proposal to increase the residential customer charge by nearly $5.00 fails to comport with widely accepted rate design principles, would adversely impact many low-income customers, and runs counter to energy

efficiency and conservation. Any increase in the customer charge should therefore be rejected.

5. The Company's proposed decoupling mechanism is generally sound but should be modified to provide greater customer protections by imposing a cap of 2.5 percent of *distribution* revenues, rather than total revenues.

6. The Company's proposed grid modernization investments should first be addressed in the context of a Least Cost Integrated Resource Plan, consistent with RSA 378:38, and should not be approved in this docket.

Q **Does this conclude your testimony?**

A Yes, it does.