BEFORE THE
STATE OF NEW HAMPSHIRE
PUBLIC UTILITIES COMMISSION

DOCKET NO. DE 21-030

IN THE MATTER OF: UNITIL ENERGY SYSTEMS, INC.
REQUEST FOR CHANGE IN RATES

DIRECT TESTIMONY

OF

LARRY BLANK
ON BEHALF OF
New Hampshire Department of Energy

NOVEMBER 23, 2021

Contents

I. IDENTIFICATION 1

II. PURPOSE AND SUMMARY 2

III. COMPANY'S REVENUE DECOUPLING PROPOSAL 3

IV. DESIGN CONCERNS WITHIN THE PROPOSED REVENUE DECOUPLING MECHANISM 14

V. LED LIGHTING RATES 19

VI. TIME OF USE RATE DESIGN 23

I. IDENTIFICATION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS FOR THE RECORD.

A. My name is Larry Blank. My business address is Transform Consulting, LLC, 8701 Camden Street, Alexandria, VA 22308.. My email address is Larry@transformconsulting.com..

Q. WHERE ARE YOU EMPLOYED?

A. I am a principal of Transform Consulting, LLC. I am also a Professor of Economics and Associate Director with the Center for Public Utilities in the College of Business at New Mexico State University ("NMSU"). For the purposes of this proceeding, I have been engaged through Transform Consulting, the expert opinions expressed herein are my own, and nothing in this testimony necessarily reflects the opinions of NMSU.

Q. PLEASE PROVIDE A BRIEF SUMMARY OF YOUR BACKGROUND AS IT IS RELEVANT TO THIS TESTIMONY.

A. I have served the public in various capacities for over thirty-five years. In 1994, I received a Ph.D. in Economics from The University of Tennessee, specializing in Industrial Organization & Public Policy (including regulatory policy), Econometrics, and Finance. I previously served as an Economist with the National Regulatory Research Institute ("NRRI") at the Ohio State University and later as the Manager of Regulatory Policy & Market Analysis with the Regulatory Operations Staff of the Nevada Public Utilities Commission. My division's responsibilities in Nevada included participation in several rulemaking workshops (primarily telecommunications and electricity) and rate cases for all regulated utilities in that jurisdiction as well as expert witness testimony on the same. As a consultant, I have served a variety of clients including government agencies, utility customers, and utility companies. I have served as an expert witness and/or advisor in over 150 rate cases and rulemakings of various types. I have previously filed written testimony in the following utility regulatory commission jurisdictions: Alaska, Arizona, Arkansas, Colorado, Delaware, Georgia, Kansas, Montana, Nevada, New Mexico, Oklahoma, Texas, and the Federal Energy Regulatory Commission. I also teach advanced graduate utility regulation to the Masters of Economics students at NMSU who have elected to specialize in this profession, I direct a professional Graduate Certificate Program in Public Utility Regulation & Economics, and I help deliver nationally-recognized rate case training programs, which are attended by hundreds of regulatory professionals from across the United States and are endorsed by the National Association of Regulatory Utility Commissioners ("NARUC"). My resume is attached as Attachment LB-1.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of the New Hampshire Department of Energy.

II. PURPOSE AND SUMMARY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I am testifying in response to Until Energy Systems, Inc.'s ("UES" or "Company") request for change in rates pending before the New Hampshire Public Utilities Commission ("the Commission"). Specifically, I will address the Company's request for approval of a revenue decoupling mechanism ("RDM") sponsored by Mr. Timothy

Lyons, the LED lighting rates sponsored by Mr. John Taylor, and the domestic time of use rates sponsored by Mr. John Taylor.

Q. PLEASE SUMMARIZE YOUR REVIEW AND RECOMMENDATIONS.

First, the rationales provided by Mr. Lyons in support of full decoupling lack merit and leave out important considerations for the Commission. If the Commission finds sufficient merit upon completion of the evidentiary record in this case, I provide recommended modifications to the detailed design of the decoupling mechanism proposed by the Company. Second, the Company has proposed LED rates that mirror the existing non-LED rates for lighting fixtures with comparable illumination capabilities. This method is not cost-based and results in LED rates that are not just and reasonable. I offer an adjustment to the proposed LED rates to recognize the reduction in demand and system capacity used by LED fixtures relative to non-LED fixtures. This also recognizes the benefit to all customers on the distribution system from the reduction in capacity requirements to meet total customer demand. Third, the domestic time of use rates proposed by the Company should include time varying rates on the distribution cost component of service and not only the transmission and generation components.

III. COMPANY'S REVENUE DECOUPLING PROPOSAL

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF REVENUE DECOUPLING

A. In traditional cost of service ratemaking, a utility's distribution revenue requirement is generally set through periodic rate cases. Based on that revenue requirement, customers generally pay a fixed price for the distribution utility's services until the next rate case when the revenue requirement is updated.[1] Once the revenue requirement is set, any variation in utility sales between rate cases which lead to revenues which are either above or below the allowed revenue requirement impact the utility's effective return, rather than ratepayers, because customer prices are generally fixed between rate cases.[2] These earnings impacts go in both directions, positive and negative. An abnormally warm summer, cool winter, or booming economy could lead to increases in sales that increase an electric distribution utility's effective return between rate cases, while an abnormally cool summer, warm winter, or economic downturn could lead to decreases in sales that decrease an electric distribution utility's effective return between rate cases. Revenue decoupling is a rate adjustment mechanism which, unlike traditional cost of service regulation, holds utility revenues constant during the years between rate cases by adjusting the customer price based on the level of sales.

Q. HAS THIS COMMISSION CONSIDERED IMPLEMENTATION OF REVENUE DECOUPLING IN THE PAST?

A. Yes, several times. The Commission conducted an extensive review of revenue decoupling in Docket No. DE 07-064, an Investigation of Energy Efficiency Rate Mechanisms, where it concluded that a rate adjustment mechanism such as decoupling could reduce barriers to utility investment in energy efficiency, but that such mechanisms should be considered within individual utility rate cases so that any impact that decoupling might have on a utility's cost of capital could also be incorporated.[3] The

[1] In practice, there are several exceptions to this general concept, including step adjustments for non-growth plant in service subsequent to a test year, non-distribution rate adjustments related to generation or transmission services, and other costs or programs which the Commission may have approved for cost recovery between rate cases.
[2] In this context, "prices" may refer to either a monthly customer charge, a volumetric ($/kWh) distribution charge, or a demand (kW) charge.
[3] DE 07-064, Order No. 24,934 at 22. (January 16, 2009).

Commission later considered its first full decoupling proposal in the context of a natural gas rate case in Docket No. DG 10-017.[4] Within the settlement that led to the order ultimately resolving that case,[5] the utility agreed to withdraw its decoupling proposal.[6] More recently, when the Commission adopted its Energy Efficiency Resource Standard ("EERS") in 2016, it granted each electric and natural gas distribution utility a limited form of decoupling known as a Lost Revenue Adjustment Mechanism ("LRAM") and required the regulated distribution utilities to "seek approval of a decoupling or other lost-revenue recovery mechanism as an alternate to the LRAM in their first distribution rate cases after the first EERS triennium."[7] The first EERS triennium ended on December 31, 2020. Since the Commission established the EERS, it has reviewed and approved two full decoupling mechanisms: one in Docket No. DG 17-048 for a natural gas distribution utility,[8] and one in Docket No. DE 19-064 for an electric distribution utility.[9]

Q. WHAT IS A LOST REVENUE ADJUSTMENT MECHANISM?

A. In this context, a lost revenue adjustment mechanism ("LRAM") is a form of limited decoupling which attempts to compensate a utility between rate cases for a hypothetical level of distribution revenues it would have otherwise received if its sales had not been

[4] There are generally three types of decoupling: full decoupling, partial decoupling, and limited decoupling. Full decoupling insulates a utility's revenue collections from any sales variation regardless of the cause. Partial decoupling insulates only a portion of the utility's revenue collections from sales deviations. Limited decoupling only adjusts a utility's revenue collections for specified causes of variations in sales. In DE 21-030, Unitil has proposed full decoupling.
[5] DG 10-017. Order No. 25,202. (March 10, 2011).
[6] The decoupling proposal faced vigorous opposition from Commission Staff, as detailed by the pre-filed testimony of Thomas C. Frantz and Mark A. Naylor. (October 22, 2010). Available at: https://www.puc.nh.gov/regulatory/CASEFILE/2010/10-017/TESTIMONY/10-017%202010-10-22%20NAYLOR-FRANTZ%20TESTIMONY.PDF
[7] DE 15-137, Order 25,932 at 59-60. (August 2, 2016).
[8] DG 17-048. Order No. 26,122. (April 27, 2018)
[9] DE 19-064. Order No. 26,376. (June 30, 2020)

diminished as a result of its energy efficiency program offerings. LRAM is limited to projected revenue effects caused by approved energy efficiency programs or net metering programs and, unlike revenue decoupling, does not allow for rate adjustments due to other factors such as weather fluctuations and economic business cycles. As mentioned above, the Commission approved LRAMs for all regulated distribution utilities when it established an energy efficiency resource standard in 2016. This decision effectively reversed an action taken by the Commission in 1998, as part of restructuring, to eliminate the lost revenues portion of its conservation and load management programs under the to-be restructured utility regulatory paradigm.[10] Under the energy efficiency LRAM, the Company recovered $995,390 of lost revenues from customers for the period of 2017-2020.[11] Similarly, the Commission approved an LRAM for the Company's net metering program in Docket No. DE 15-147.[12] Under the net metering LRAM, the Company recovered $940,400 of lost revenues from customers for the period of 2017-2020. In total, the Company has collected $1,935,790 in total lost distribution revenues for the period since its last rate case.[13] In contrast, as shown in Table 1, below, the Company's actual overall kWh sales volumes fell by approximately 0.67% on average annually

[10] DR 96-150. Order No. 22,875 (March 20, 1998) (stating "We also believe that it is appropriate to move as quickly as possible from the payment of lost revenues as part of any DSM program.") See also, Order No. 23,573 (November 1, 2000)(stating "Consistent with Order No. 22,875, we continue to believe that it is appropriate to move as quickly as possible from the payment of lost revenues as part of any energy efficiency programs and will deny recovery of lost revenues on a forward-going basis.")
[11] DE 17-136. Unitil Energy Systems, Inc. 2020 Annual Report. Attachment B. Page 1 of 1. Available at: 2020 Annual Report UES LBR.xls (nh.gov)
[12] Docket No. DE 15-147. Order No. 25,991 (February 21, 2017).
[13] Docket No. DE 21-121. Douglas J. Debski Testimony. Page 5 of 7. Available at: https://www.puc.nh.gov/regulatory/Docketbk/2021/21-121/INITIAL%20FILING%20-%20PETITION/21-121_2021-06-17_UES_TESTIMONY_DEBSKI.PDF

during that same period.[14] For non-demand-charge residential and small general service customers, the average annual change was actually positive 1.67% over this period.

Table 1.
Unitil Distribution Sales Volumes

Year	2016	2017	2018	2019	2020
Total kWh*	1,191,932,155	1,188,641,108	1,224,436,868	1,162,491,979	1,160,418,601
Annual Change		(3,291,047)	35,795,760	(61,944,889)	(2,073,378)
Percent Annual Change		-0.276%	3.011%	-5.059%	-0.178%
Average Annual Change				-0.775%	-0.626%

Year	2016	2017	2018	2019	2020
Residential - D*	484,321,778	484,341,433	510,593,306	483,929,101	515,968,592
Small General Service - G2*	549,564	502,127	512,615	500,439	438,744
Small General Service - QR WH/SH*	4,832,208	5,112,600	5,612,997	4,942,809	4,483,579
Total Non-Demand kWh	489,705,566	489,958,177	516,720,936	489,374,368	520,892,935
Annual Change		252,611	26,762,759	(27,346,568)	31,518,567
Percent Annual Change		0.05%	5.46%	-5.29%	6.44%
Average Annual Change				0.074%	1.67%

*Source: Unitil response Staff 2-31 Attachment 1.

Put simply, the LRAMs are supposed to target lost distribution revenues associated with energy efficiency and net metering, but instead *compensates utilities for revenues that they may not have actually lost* because the loss either didn't actually occur, or may be offset by higher sales volumes resulting from weather variations or economic growth. In this sense, it is an asymmetric mechanism, resulting only in surcharges to customers between rate cases. In contrast, decoupling is a symmetrical mechanism, which may result in either a surcharge or a credit, depending on a universe of factors—such as market trends, weather and economic downturns or upswings — which may be beyond the control of either the utility or the ratepayer.

Q. WHAT RELATIONSHIP DOES THE COMPANY'S LOST REVENUE ADJUSTMENT MECHANISM HAVE TO ITS DECOUPLING PROPOSAL?

[14] Company Response to Request DOE 2-31, Attachment 1. Included here as Attachment LB-2.

A. When the Company adopts decoupling, it will cease collection of lost revenues associated with both its energy efficiency and net metering programs.

Q. DOES DECOUPLING HAVE ANY DRAWBACKS?

A. Yes, several. As I mentioned, decoupling is a mechanism which may result in both credits and surcharges, depending on a broad universe of factors—such as market trends, weather and economic downturns or upswings — which are beyond the control of the utility and ratepayers. In times of consistent economic growth or state policies that are supportive of electrification, decoupling could, in theory, result in consistent credits to customer bills during years between rate cases. But in times of economic downturn when sales drop sharply, consumers see that downturn in the form of surcharges on their bills, surcharges which allow the Company to consistently collect its approved revenue requirement. In the case of revenue per customer decoupling in particular, the Company will be made whole not just for lost sales volumes, but also for other revenues unrelated to sales that may be less in between rate cases than they were in the test year. For example, during a partial or widespread system outage, the Company's incentive to restore service quickly will be diminished because the revenue per customer target will not change, and the Company will collect those missing revenues from customers through the decoupling adjustment.

Q. WHAT PURPORTED BENEFITS ARE PROVIDED BY MR. LYONS TO JUSTIFY THE DECOUPLING MECHANISM?

A. Mr. Lyons states the following "three primary benefits of the Company's proposed RDM:"

1. It corrects the basic misalignment between utility rates and costs;

2. It supports achievement of certain policy objectives, such as EE and DER initiatives; and

3. It helps stabilize utility cost recovery as well as customer bills.[15]

Q. ARE THESE ISSUES WORTHY OF CONSIDERATION?

A. Yes, I believe these are considerations for the Commission; however, a broader discussion of the potential benefits and drawbacks of decoupling than what the Company has presented should also be considered by the Commission.

Q. IF THE COMMISSION CHOOSES NOT TO APPROVE CHANGES IN RATE DESIGN OR FULL REVENUE DECOUPLING, WILL THESE ISSUES PROVE TO BE FINANCIALLY BURDENSOME FOR THE COMPANY?

A. No. Electric utilities have successfully operated for over 120 years without the need for revenue decoupling. If the Commission chooses to not act on this request, UES can continue to be managed financially well without the proposed RDM. Electric utility investors understand that there will be good years and bad years in terms of revenue and earnings, and proper management of the electric utility includes managing this short-term risk. If the Commission does choose to act on this request, it should be sure to examine the Company's cost of capital in light of the revenue assurance provided by decoupling.[16]

Q. HOW DO YOU ADDRESS THE FIRST ISSUE IDENTIFIED BY MR. LYONS, THE BASIC MISALIGNMENT BETWEEN UTILITY RATES AND COSTS?

---

[15] Lyons Direct Testimony at 7:5-9.

[16] *See*, DG 17-048. Order No. 26,122 at 1, 42-43. (April 27, 2018) Stating ("In this order, the Commission approves, for the first time in New Hampshire, a decoupling mechanism which allows rate adjustments for weather, energy efficiency, economic effects, and other variables and allows Liberty to earn distribution revenues on a per customer basis, thus eliminating substantial revenue risks. Paired with this innovative decoupling mechanism is a modified rate design that lowers fixed customer charges. The reduction in risk leads to a return on equity of 9.3 percent, which represents a 10 basis point reduction in the return on equity agreed to by Liberty, the OCA, and Staff.")

A. The concern here is the heavy reliance on variable energy charges for the recovery of fixed customer-related costs and/or demand- or capacity-related costs. Although the use of volumetric charges for fixed cost recovery has been used successfully for many decades, the proposed RDM fails to realign rate design appropriately and actually distorts cost recovery further by imposing the RDM rate adjustments through the volumetric energy usage. This causes cost-shifting away from those who fail to pay their fair share toward fixed cost recovery onto those who contribute most to fixed cost recovery through their energy usage. Mr. Lyons' statement that "[r]evenue decoupling corrects for this misalignment by adjusting revenues to match the authorized revenue requirements"[17] fails to acknowledge the continued misalignment between rate design and fixed cost recovery and the failure of revenue decoupling to match cost recovery with customer beneficiaries who demand greater capacity built into the system.

Q. HOW DO YOU ADDRESS THE SECOND ISSUE RAISED BY MR. LYONS WHICH IS THE SUPPORT OF ENERGY EFFICIENCY AND DISTRIBUTED ENERGY RESOURCE POLICY INITIATIVES?

First, revenue decoupling does not alter electric utility shareholder incentives toward energy reduction on the customer side of the meter. Shareholder wealth and return are enhanced by asset growth, but energy efficiency ("EE") programs and distributed energy resources ("DER") offset that growth potential. Revenue decoupling does not alter this fact. Revenue decoupling reduces short-term risk associated with variability in short-term revenue between rate cases but does not change the long-term desire to maximize returns to investors, earnings growth potential will be reduced when competition in the

[17] Lyons Direct at 8:7-8.

form of EE programs and DER take business away from the utility. While I would agree that decoupling reduces the throughput incentive between rate cases, in the case of restructured utilities that do not own generating assets, such as Unitil, the kWh throughput incentive is already greatly diminished. The more important incentive that drives investment for distribution utilities is the profit incentive to expand their rate base, on which decoupling has no impact.

Q. PLEASE DESCRIBE THE PROFIT INCENTIVE TO EXPAND RATE BASE.

A. Under traditional cost of service ratemaking, utility shareholder profit is enhanced by continued investment in capital assets upon which the Company may earn a rate of return. In practice, this leads companies to seek out capital-intensive technologies and/or take advantage of other opportunities to build rate base. For distribution utilities, one of the largest historical opportunities for rate base growth has been focused on capacity-related investments. Decoupling does nothing to eliminate the Company's incentive to grow demand, because demand growth requires the Company to make capacity-related investments which it then earns a rate of return upon. EE programs and DER have the potential to diminish the need for these investments through their ability to reduce demand growth, especially in the case of energy efficiency measures which are targeted towards an anticipated capacity constraint. Decoupling does nothing to alter this incentive, which would cause utilities to skeptically view targeted EE program, DERs, and any other demand reducing measures that might diminish rate base growth.

Q. HOW DO YOU ADDRESS THE THIRD CLAIM MADE BY MR. LYONS, THE STABILIZATION OF COMPANY REVENUE AND CUSTOMER BILLS?

A. On the one hand, revenue decoupling does shield the utility company from revenue variability due to such things as seasonal weather fluctuations, but it actually shifts this risk onto customers who continue to face bill variation each year as well as a revenue decoupling adjustment factor. While this shifting can actually result in credits to a customer bill during times of economic growth or an abnormally warm summer, it may also result in surcharges to a customer bill during times of economic downturn, precisely when customers can least afford to pay such surcharges. Furthermore, there are likely to be years in which the Company is recovering an under-recovery from the prior year(s) during an abnormally cold winter and/or abnormally hot summer thereby causing already high electric bills to be even higher during such years.

Q. DO YOU SEE ANY OTHER GENERAL CONCERNS WITH DECOUPLING?

A. Yes. An additional concern is decoupling is a form of retroactive ratemaking. Another concern is decoupling is piecemeal or single-issue ratemaking.

Q. WHAT IS RETROACTIVE RATEMAKING?

A. Retroactive ratemaking occurs when rate adjustments are made related to events that occurred in the past. In the case of decoupling, rate adjustments will occur based on customer usage or demand in the prior year. The customers have already paid the prior year bills based on the approved rates, but then a decoupling adjustment changes what has already been billed and paid in the prior year. Most Commissions prohibit retroactive ratemaking, but if decoupling is approved, then there is an argument that the Commission is effectively authorizing retroactive ratemaking. On the other hand, there is also an argument that if the decoupling formula is described in the utility tariff, then customers do have advance, rather than retroactive, notice of how their rates will change in the current year responsive to prior year sales. Both of these arguments would be applicable not just to decoupling, but also the existing lost revenue adjustment mechanisms that decoupling would replace.

Q. WHAT IS PIECEMEAL OR SINGLE-ISSUE RATEMAKING?

A. Piecemeal or single-issue ratemaking occurs when rate adjustments only account for one change while ignoring other changes or adjustments that may counter the need for that rate adjustment. In the case of decoupling, rate adjustments will be made based on changes in sales while ignoring other possible changes that may have occurred. Changes in rate base, cost of financial capital, changes in expenses, and changes in class cost of service would normally be accounted for within a general rate case, but with decoupling, these other changes will be ignored in the calculation of the decoupling rate adjustment. Most Commissions disfavor single-issue ratemaking, but if decoupling is approved, then there is an argument that the Commission is effectively authorizing single-issue ratemaking adjustments. Compared to decoupling, the LRAM that decoupling would replace is an even more egregious example of single-issue ratemaking. As described above, the LRAM accounts only for theoretical revenues that would be lost to net metering or energy efficiency if all else remains equal from the test year, and ignores other changes such as sales fluctuations, which actually counteract the need for the LRAM rate adjustment because those revenues were not actually lost.

Q. WHAT IS YOUR RECOMMENDATION FOR THE PROPOSED RDM?

A. Based on my previous explanations, the Company's justifications for its proposed RDM lack merit and leave out other important considerations. The primary benefit of the Company's RDM would be to provide greater revenue certainty for the Company. From

Direct Testimony of Larry Blank
NH PUC Docket No. DE 21-030

a ratepayer perspective, decoupling would eliminate the various lost revenue adjustment mechanisms that compensate the utility for theoretical lost revenues, revenues which may not have actually been lost. It would also potentially reduce the risk to the utility that it would not realize its revenue requirement between rate cases, a risk reduction which the Commission should recognize when it considers the Company's cost of capital. I also have serious concerns about cost shifting, and cost misallocation if the Commission were to adopt the Company's proposed RDM. If the Commission finds merit in approving some form of full decoupling, I offer revisions to the design of the RDM in the next section of my testimony.

IV. <u>DESIGN CONCERNS WITHIN THE PROPOSED REVENUE DECOUPLING MECHANISM</u>

Q. HOW IS THE PROPOED RDM STRUCTURED?

A. UES has proposed a "Revenue Decoupling Adjustment Clause" ("RDAC") that would apply to six customer classes and adjust rates on an annual basis to reconcile actual base revenues per customer with authorized base revenues per customer as determined in the last rate case. The best place to understand the structure and detailed steps in calculating this adjustment mechanism is by looking at UES's proposed tariff sheets for the RDAC found as Schedule TSL-2 of Mr. Lyons Direct Testimony. Each of the six customer classes would have a revenue decoupling adjustment factor ("RDAF") which would be a rate per kWh. Each RDAF is derived from an aggregate annual revenue variance, which is the sum total of the 12 monthly revenue variances for all six customer classes. This aggregate annual revenue variance plus carrying costs and any balance from the prior year is termed the Revenue Decoupling Adjustment ("RDA"). This aggregate total company RDA is then allocated to each customer class based on the ratio of each class authorized base revenues divided by total authorized base revenues. The customer class RDA is then divided by forecasted kWh sales to derive the RDAF for that class.

Q. HAS UES ALSO PROPOSED AN ANNUAL CAP ON THE RDA?

A. Yes, UES is proposing an asymmetrical cap of 2.5 percent of total revenues for negative RDAs that result in a positive adjustment to customers in the subsequent year. Any difference between the RDA and this cap then would be added to the reconciliation balance for future recovery in the next annual RDAC calculation.

Q. DO YOU HAVE ANY DESIGN CONCERNS WITH THE PROPOSED RDAC?

A. Yes. My first concern is the aggregation of all the customer classes in the determination of a total company annual RDA, and then reallocation of that total back to the customer classes. Not all customer classes will share equally in the need for an adjustment. Therefore, it is unjust and unreasonable to spread under- or over-recovery across all customer classes. This will result in a deviation from the Commission approved revenue requirements determined for each customer class within the last rate case. Once those customer class revenue requirements are deemed to be just and reasonable by the Commission, there should not be an adjustment mechanism that alters that determination. In some year you may have a customer class in which UES over-recovered revenue but then the other classes had under-recovery. If the under-recovery from the other classes is greater than the over-recovery there will be a positive RDAF for all the classes, which is unjust and unreasonable.

Q. HOW WOULD YOU CORRECT THIS FIRST CONCERN?

A. A revenue decoupling mechanism should be designed such that the calculations of over- and under-recovery are independently done within each customer class subject to revenue decoupling. The RDAF for a customer class should be calculated strictly from over- and under-recovery within that class without any aggregation of customer classes. For example, all calculations for residential customers should be independently done separately from any other customer classes with revenue decoupling and any rate adjustment should only apply to that customer class.

Q. DO YOU HAVE A SECOND CONCERN WITH THE PROPOSED RDAC?

A. Yes. It is unclear why UES is proposing decoupling for the large general service ("LGS") class and regular general service with demand charges. First, these customers have no distribution revenue collection through energy charges. Second, these classes tend to be very diverse in terms of annual and monthly billing and, therefore, the meaning of the per customer revenues used within the proposed RDAC becomes questionable. Third, the diversity within these general service classes implies that some customers within the class have very large monthly bills and some within the class have relatively small bills. A change in the revenue from one large customer will impact the other customers within the class. Such a change could be a large reduction in production activity due to an economic recession or even discontinuance of service by a larger customer, thereby causing a shift in that revenue recovery onto smaller commercial customers. When such substantive changes occur, a general rate case will include corresponding reduction in class demand and reduction in class cost of service. Because decoupling constitutes single-issue ratemaking, as I discussed earlier, the change in class cost of service is not accounted for within the decoupling rate adjustment for the class.

Q. HOW WOULD YOU CORRECT FOR THIS SECOND CONCERN?

A. I recommend that the Commission deny any revenue decoupling for LGS customers and other general service customers with demand charges.

Q. DO YOU ALSO HAVE A CONCERN WITH THE PROPOSED REVENUE DECOUPLING CAP?

A. Yes. The asymmetrical design of the proposed cap in which it only applies to under-recovery and not over-recovery may seem attractive to some. However, because any amounts above the cap are deferred to the next reconciliation period with a carrying charge, it is not really a cap. Although I agree that a cap is reasonable to avoid possibly large adjustments in some years, the carry forward of these amounts should not be allowed.

Q. HOW WOULD YOU CHANGE THE DESIGN OF THE REVENUE DECOUPLING CAP?

A. First, I recommend that a cap be symmetrical in that it applies to both under-recovery and over-recovery each year. Second, I recommend that the revenue decoupling cap be a hard cap without any carry forward for amounts above the cap. For example, it would be reasonable to impose a symmetrical hard cap without carry forward in which any annual adjustment shall not exceed five percent (5%) of base distribution rate revenues. Because the hard cap applies symmetrically to both under- and over-recovery of the target per customer revenue, it is fair to both the customers and the Company, and the hard cap avoids the potential accrual of large deferred balances with an additional carrying charge.

Q. DOES A HARD CAP WITHOUT ANY CARRY FORWORD RETAIN ANY POSITIVE INCENTIVES?

A. Yes. Currently the Company has a strong positive incentive to restore service quickly when outages occur. Another concern with decoupling is the possibility that this incentive disappears because the Company recovers revenue lost during the outage. A hard cap without carry forward helps to retain the Company incentive to restore service as quickly as possible albeit maybe not completely depending on the time of year the outage occurs.

Q. ARE THERE ADDITIONAL MEASURES THAT COULD BE ADDED TO ENSURE THE COMPANY RETAINS THE INCENTIVE TO RESTORE SERVICE QUICKLY WHEN OUTAGES OCCUR?

A. Yes. An additional measure would be to deduct the actual number of customers in the decoupling calculations by the percentage of customer outage hours to total annual customer hours, where customer hours is the number of customers times the number of hours in the year and customer outage hours is the number customers without power times the number of outage hours.[18]

Q. HAVE YOU NOTICED ANY OTHER CONCERN WITH THE PROPOSED BILLING OF THE REVENUE DECOUPLING ADJUSTMENT CHARGE?

A. Yes. UES is proposing to apply the Revenue Decoupling Adjustment Charge to other customer classes that are not part of the RDA calculations. For example, there is a proposed addition to the Outdoor Lighting Service tariff schedule which states:

> Revenue Decoupling Adjustment Charge: All energy delivered under this Schedule shall be subject to the Revenue Decoupling Adjustment Charge as provided in Schedule RDAC of the Tariff of which this is a part.

[18] This would implement a suggestion made in RAP (2016) "Revenue Regulation and Decoupling: A Guide to Theory and Application," p. 49.

It is unclear why Outdoor Lighting customers who pay fixed monthly charges for distribution service are being asked to contribute toward a decoupling adjustment as if it is some public service program. This seems to be indicative of the Company's attitude that cost shifting within and between rate classes is fine within the context of revenue decoupling, but the reality is it is unjust and unreasonable.

Q. WHAT IS YOUR RECOMMENDATION FOR THE REVENUE DECOUPLING ADJUSTMENT CHARGE?

A. Consistent with my recommendation above that all decoupling calculations be done within individual customer classes so must the decoupling adjustment. Other customer classes should not be responsible for revenue requirements approved for a particular customer class.

Q. WOULD YOU LIKE TO SEE ADDITIONAL CLARITY ON ANY OTHER PROVISIONS WITHIN THE PROPOSED TARIFF LANGUAGE FOR SCHEDULE RDAC?

A. Yes. The definitions for Actual Base Revenues and Authorized Base Revenues states that these include revenues recovered through the Company's customer charge and distribution charges. Additional clarity is needed to state the following: "This only includes base distribution rate revenues recovered from that Customer Class through the Company's customer charge and distribution charges, and excludes rider revenue and any other revenue." It is important that any variation in other revenue not be factored into the decoupling calculations.

V. LED LIGHTING RATES

Q. HAVE YOU REVIEWED THE PROPOSED LED LIGHTING RATES?

A. Yes, the Company has proposed new LED rates for Outdoor Lighting Service (Schedule OL) which mirror the proposed rates for legacy lighting technology with comparable illumination capabilities.

Q. DO YOU HAVE ANY CONCERNS WITH THE COMPANY'S APPROACH TO INTRODUCE NEW LED RATES?

A. Yes. The LED lights impose less demand and less required capacity on the distribution system, however, the use of the comparable lighting rates fails to recognize the lower demand from LED lighting which should translate into less demand-related costs paid by these LED customers.

Q. HAVE YOU COMPUTED THE REDUCTION IN DEMAND?

A. Yes. Based on Schedule RJA-4, unit cost of service results, 12.87% of the costs allocated to Outdoor Lighting are demand related costs. My calculations of the LED demand reductions and demand related costs are provided in Table 2, below.

Table 2: OL Rates for Company Paid LED Fixture			Demand:	12.87%					
Line No.	Outdoor Lighting LED Type	LED Watts	Sodium Vapor Watts	LED to Sodium Ratio	Sodium Demand Cost	LED Demand Cost	UES Proposed Rate	Revised LED Rate	Percent Reduction
1	STREETLIGHT LED 30W	30	50	60.0%	$ 1.77	$ 1.06	$ 13.73	$ 13.02	-5.15%
2	STREETLIGHT LED 50W	50	100	50.0%	$ 2.03	$ 1.01	$ 15.73	$ 14.72	-6.44%
3	STREETLIGHT LED 100W	100	150	66.7%	$ 2.22	$ 1.48	$ 17.25	$ 16.51	-4.29%
4	STREETLIGHT LED 120W	120	250	48.0%	$ 2.51	$ 1.21	$ 19.53	$ 18.22	-6.69%
5	STREETLIGHT LED 140W	140	400	35.0%	$ 3.19	$ 1.12	$ 24.78	$ 22.71	-8.37%
6	STREETLIGHT LED 260W	260	1,000	26.0%	$ 5.47	$ 1.42	$ 42.51	$ 38.46	-9.52%
7	YARDLIGHT LED 35W	35	50	70.0%	$ 1.73	$ 1.21	$ 13.44	$ 12.92	-3.86%
8	YARDLIGHT LED 47W	47	100	47.0%	$ 1.89	$ 0.89	$ 14.65	$ 13.65	-6.82%
9	FLOODLIGHT LED 70W	70	150	46.7%	$ 2.35	$ 1.10	$ 18.25	$ 17.00	-6.86%
10	FLOODLIGHT LED 90W	90	250	36.0%	$ 2.78	$ 1.00	$ 21.57	$ 19.80	-8.24%
11	FLOODLIGHT LED 110W	110	400	27.5%	$ 3.25	$ 0.89	$ 25.29	$ 22.93	-9.33%
12	FLOODLIGHT LED 370W	370	1,000	37.0%	$ 5.52	$ 2.04	$ 42.89	$ 39.41	-8.11%

Q. DO YOU HAVE ANY OTHER RECOMMENDATIONS REGARDING THE COMPANY'S OUTDOOR LIGHTING RATES?

A. Yes. As I understand it, the other two regulated electric distribution utilities in New Hampshire recently redesigned their street lighting rates to include customer contributed LED options. In Docket No. 19-064, the Commission approved a settlement with Liberty Utilities which provides for a customer-contributed LED lighting rate that allows the customer to purchase the fixture from the Company rather than be billed monthly for leasing the fixture, but to also retain title to the fixture so remains non-taxable.[19] It also allowed municipalities, at their option, to take on the maintenance responsibilities of the fixtures so they may fully realize the operational and maintenance savings of the LED fixtures relative to high pressure sodium or other legacy fixtures. The new offering also included language that would allow municipalities to utilize — and be billed according to actual usage resulting from the use of — advanced lighting controls for dimming, trimming, and brightening during any given month. In Docket No. DE 19-057, the Commission approved a settlement providing for very similar revisions to the Eversource street lighting tariff, as well as revised burn hours that more closely match those agreed upon during the Liberty case. Eversource recently filed its proposed tariff in Docket No. DE 21-071.[20] I recommend that Unitil adopt these above-described provisions in their street lighting tariff as well.

---

[19] Docket No. DE 19-064. Settlement Attachment. Bates 238-241. (May 26, 2020) Available at: 19-064_2020-05-26_GSEC_ATT_STIPULATION_SETTLEMENT_AGRMT.PDF

[20] Docket No. DE 21-071. Eversource Original Page 86. Available at: 21-071_2021-03-31_EVERSOURCE_STREETLIGHT_TARIFF.PDF

VI. TIME OF USE RATE DESIGN

Q. PLEASE SUMMARIZE UNITIL'S WHOLE HOME TIME OF USE RATE PROPOSAL.

A. Unitil's whole home time of use rate proposal (Domestic TOU Rate) provides for a time-varying transmission and generation components. This rate differs from the separately-metered electric vehicle rate in that the distribution component does not vary according to time of use, and the customer charge is higher.

Q. DO YOU AGREE WITH RECOMMENDATIONS REGARDING RESIDENTIAL CUSTOMER CHARGES IN THE TESTIMONY OF WITNESS JASON BALL?

A. Yes, with one qualifier. Witness Ball discusses a recommended customer charge for the residential rate, but does not speak to the appropriate level of customer charge for the domestic TOU rate. There is at least a colorable argument that the domestic TOU rate should vary some from the residential rate, because metering facilities capable of transmitting interval data might be slightly more expensive that the metering facilities a residential customer would otherwise use. However, many in the industry argue that incremental costs associated with interval metering should be classified as demand related costs, rather than customer related costs, and therefore recovered via a volumetric rate rather than through the customer charge.[21]

[21] See, Regulatory Assistance Project. Smart Rate Design for a Smart Future. Appendix D at D-6; Appendix A at A-6; and Appendix A at A-4. (stating "additional cost of smart [also known as AMI] meters is justified by many benefits beyond the simple measurement of usage . . . and this additional cost is not properly considered customer related."); *See* also, Rocky Mountain Institute, A Review of Alternative Rate Designs: Industry Experience with Time-Based and Demand Charge Rates for Mass-Market Customers, 54 (2016)(Stating "[i]n some situations, a portion of AMI (and other 6 smart-grid infrastructure) costs may be appropriately recovered through energy or demand charges.")

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSAL TO VARY TRANSMISSION AND GENERATION COMPONENTS BY TIME OF USE, BUT NOT DISTRIBUTION COMPONENTS?

A. I agree with Witness Taylor that as a matter of economic efficiency, fixed system costs should generally be recovered via fixed charges including demand charges. However, in testimony, Witness Taylor states that "the costs associated with the distribution system are fixed in nature. These costs do not vary by time of day and as such have no bearing on the developing a time-of-use rate that is purely cost causative." I disagree with this premise because it focuses entirely on short run costs, and fails to understand that the need for system upgrades are often driven by capacity-related system constraints during a limited number of system peak hours. Sending price signals that shift demand away from peak periods will, in the long run, limit the need for capacity related investments and provide for a better system load factor, spreading the costs of the existing system kW capacity over more kWhs. The rate base investment incentive discussed above provides a bias for regulated electric distribution utilities to avoid the use of such price signals, even when the reduced need for capacity-related upgrades would potentially translate to lower customer rates.

Q. WHAT ARE YOUR RECOMMENDATIONS REGARDING THE WHOLE HOME TIME OF USE RATE?

A. As such, I recommend that Unitil revise its domestic TOU rate to incorporate a customer charge based on the basic customer method identified in the Witness Ball's Testimony. I also recommend that Unitil revise its domestic TOU rate to incorporate a volumetric time varying distribution component, based upon the methodology the Company has used for its separately metered electric vehicle rate.

Q. DO YOU HAVE ANY RECOMMENDATIONS REGARDING THE SEPARATELY METERED ELECTRIC VEHICLE TOU RATES?

A. No. As I understand it, those rates will be resolved in a separate proceeding, Docket No. DE 20-170.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.