STATE OF NEW HAMPSHIRE

BEFORE THE

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

DOCKET NO. DE 24-070

REQUEST FOR CHANGE IN RATES

DIRECT TESTIMONY OF

Amparo Nieto

Marginal Cost of Service Study and Rate Design

On behalf of Public Service Company of New Hampshire

d/b/a Eversource Energy

June 11, 2024

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Attachments

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PETITION OF PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE d/b/a EVERSOURCE ENERGY REQUEST FOR CHANGE IN RATES

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I. INTRODUCTION

Q. Please state your name and current position.

A. My name is Amparo Nieto. My current position is Principal at Charles River Associates (CRA). At CRA, I am a senior lead of the utility rates and marginal cost practice.

Q. What is the purpose of your testimony?

A. I have prepared an electricity marginal cost of distribution service study ("MCOSS") for PSNH to be used as a guide for rate design in its current General Rate Case (GRC). In my testimony, I describe the methods employed and the underlying principles governing the choice of methods, summarize the results by rate class and discuss the main implications of the results in designing rate changes. that enhance the efficiency and equity properties of PSNH's existing distribution rates. The 2024 MCOSS results are submitted in this proceeding in Attachment ES-MCOSS-1.

Q. Have you also provided separate testimony in this rate case on the Company's allocated cost of service study?

A. Yes. I have also conducted an update to the Company's Allocated Cost of Service Study ("ACOSS") and have provided separate testimony on that topic.

Q. Please summarize your education and professional experience.

A. I am an energy regulatory economist with more than 25 years of experience. I have extensively conducted electricity and natural gas MCOS studies and recommended the appropriate use of these study results for decisions in time of use rates, new rate designs and improved equity in allocation of revenue requirement to customer classes. As part of my regulatory assignments, I have evaluated multiple Net Energy Metering (NEM) rates and supported alternative rate designs that can be adopted in lieu of the legacy NEM rates in a manner that more closely aligns the incentives of customers to adopt DERs such as behind-the-meter (BTM) solar, energy storage, and electric vehicles (EVs) with the value they can provide. In California, I was a key advisor to the energy division of the California Public Utilities Commission (CPUC) regarding the evaluation and design of policy alternatives to existing NEM and design of improve marginal cost-based rates. Prior to joining CRA, I was Vice President at NERA Economic Consulting, Senior Director at E3 and Senior Vice President at Economists Incorporated. I hold a Masters' degree in Economic Analysis from the Institute for Fiscal Studies of Madrid, Spain, and a BA in Economics from the University of Carlos III of Madrid.

II. SUMMARY OF TESTIMONY

Q. Please summarize the key findings of the marginal cost study.

A. The MCOSS evaluates all elements of marginal distribution costs of service taking into account the specific characteristics of PSNH's distribution system, its customer mix, and information on its distribution capital budget. A review of the capital budget and peak load forecasts revealed that only a small share of the upstream distribution system (substations and trunkline feeders) will require expansion of capacity to meet peak load reliably during the study period 2024 – 2028. The marginal distribution unit cost reflects this finding. The MCOSS also produces marginal cost estimates of the local distribution facilities and marginal customer costs. These last two components serve as a guide to decide on increases of the monthly fixed charges for those rates that do not include a facilities per kW charge or a monthly maximum non-coincident demand charge. The study shows a significant increase in customer and facilities costs compared to the prior MCOS in the 2019 General Rate Case (GRC) due to increases in the underlying equipment costs.

Q. Please summarize the key recommendations regarding the use of marginal cost results.

A. Eversource's rate revenue targets have traditionally been set on the basis of the Company's allocated cost of service study results. The Company continues to mainly rely on ACOSS as a guide or starting point for setting class revenue targets. Nevertheless, it is important to review if each rate class is paying at least the corresponding marginal costs of service associated with the test year, using the MCOSS results. The Company also evaluated the marginal unit cost results as an input into the decisions made regarding rate design. The Company's current rate proposals represent a significant step towards the reduction of inter-class cross subsidies, keeping in mind gradualism in changes to avoid large bill impacts. The direction of changes in revenue requirement by class suggested by the ACOSS for the major rate classes is consistent with those suggested by the MCOSS. An above-average residential class revenue requirement increase is necessary to continue moving in the right direction towards cost parity by rate class.

Q. In your opinion, how can marginal cost applied to rate design help lower costs for all customers in the long-term?

A. A key goal of marginal cost pricing in the context of utility's grid service is to ensure that price signals to customers will incentive an efficient usage of the system and therefore a more efficient expansion of the grid, compared to rates that purely reflect average accounting costs. The pace of capacity expansion investments is more likely to be in alignment with how customers value incremental electricity when using marginal cost-based rates. Revenues also do a better job of tracking the incremental usage costs, or reduction in costs associated with deceleration of peak load growth. Additionally, marginal cost studies produce information that can also be used to enhance the manner in which rates achieve intra-class equity by increasing a higher share of non-marginal costs in fixed charges as I discussed earlier. Customer acceptance and affordability (avoidance of unacceptably high bill impacts) is also an important goal and therefore gradualism in changes must be considered in any rate design decision to avoid sudden changes within the class in the move towards more cost-reflective rates that will ultimately benefit the entire customer base.

III. DEFINITION OF MARGINAL COSTS AND METHODS USED IN THE COMPANY'S RATE CASE

Q. Please define Marginal Costs.

A. Marginal cost is the cost of the additional resources needed to produce and/or deliver the next small increment of output (or the costs avoided when consumers reduce their demand by a small amount). In perfectly competitive conditions, a market-clearing price is defined by the intersection of the total suppliers' marginal supply cost curve and the aggregated demand curve. In presence of natural monopolies, such as regulated distribution service, prices equal to marginal cost would fail to produce the required revenue to recover all costs, due to the fact that distribution stations and feeders exhibit large economies of scale and investment is lumpy. Nevertheless, even in this context, marginal cost-based prices play an important role so that customers can make decisions based on how the marginal usage change impacts not only their monthly bill but also system costs. Additionally, the marginal cost incurred by the Company to provide customer access to the grid, as well as other customer-related services, need to be identified and accounted for as it represents the share of the costs that do not vary with on-going usage and therefore ideally are recovered in fixed components of the rate.

Q. Please describe the main elements of the MCOSS study.

A. The MCOSS as filed by PSNH was a forward-looking exercise over a five-year horizon. This timeframe represents the capital plan years and is overall sufficient to consider the period that PSNH typically needs to formalize a capacity solution or distribution investment (two to three years ahead of the need), without keeping it too short which would affect marginal cost price stability. The MCOSS covers the following elements of delivery service:

1. Marginal, time-related upstream delivery costs, including costs of bulk and non-bulk distribution stations, and trunk-line primary feeders that connect these substations to the more local primary lines. These are time-related costs as they are closely related to the growth in expected station peak loads. Only load increases (or reductions) in hours coincident with the station peak hours have a bearing on the marginal costs of this component of service.

2. Local distribution facilities costs, including transformers and conductors local to the customer premises (primary and secondary). These elements of plant are not expanded with near term load fluctuations, but with additions of new customers and the long-term provision of service to the customer. When a new customer begins to receive service, marginal facilities cost is represented by the cost of installing sufficient transformer and local line capacity to accommodate the customer's expected long-term maximum demand.

3. Other components of distribution equipment are strictly customer-related, such as the cost of meters and service drops.

4. On-going marginal customer-related costs such as those required to administer and process meter reads and billing, and other services.

The annualized bulk station and non-bulk substation marginal costs are averaged across all the capacity-expansion areas where the corresponding projects are located. A system-wide average marginal cost is then calculated to be helpful for distribution rate design purposes. Marginal operation and maintenance ("O&M") expenses, and loading factors are then added. The MCOSS summarizes hourly marginal upstream primary distribution station costs by time of use ("TOU") periods, using the current year-round construct of existing rates.

Q. Please describe PSNH's primary distribution system.

A. PSNH's primary voltage distribution system starts with bulk stations that are fed from the transmission system (115kV) and typically convert power to 34.5 kV or directly to 12 kV. Lower voltage distribution substations convert the load coming from the bulk station to either 12 kV or 4 kV; and trunk-line primary feeders connect the substation down to the primary tap lines. More than 80 percent of the total PSNH's retail load is served from small primary step transformers that convert the load directly coming from the bulk system to either 12.47 kV or 4.16 kV.

Q. Please describe the computation of the marginal distribution substation and trunkline feeder costs.

A. The study computed growth-related capacity expansion project dollars of investment, stated in 2025$, and estimated the marginal investment per kW of added project capacity, which was then restated as investment per kW of peak load carrying capability. Ultimately, a system-wide average marginal cost was estimated, taking into account the share of the system peak load that is served in capacity expansion areas. The starting point of the marginal high-voltage distribution cost analysis is a review of the Company's budgeted investments in both bulk and non-bulk substations during the upcoming planning period (2024-2028). Investments adding capacity to meet peak reliably can be differentiated between those addressing capacity deficiencies from the point of view of base loading conditions (N-0), and those related purely to reliability design violations related to loss of one transformer or feeder (N-1). The first investment type involves expanding a transformer when the peak load is expected to be at or above 95 percent (bulk stations) or 100% (non-bulk stations) of the nameplate rating of the transformer at any point during the five-year forecasted period. The projects selected for the MCOS study include projects when investment is triggered to meet peak load growth in a particular substation and excludes projects that are driven by the need to modernize the grid, improvements of asset condition, or replacement of aging facilities over the study period, since these are unlikely to be impacted by changes in the load. The MCOS study also excludes any investments that are solely incurred to address asset condition, such as substandard design, old electromechanical relays, stations that need low-side voltage conversion, control house condition, or other reliability-related costs that are unrelated to growth in peak load.

Q. What were the findings of your analysis of distribution station load forecasts over the five-year period?

A. I reviewed the Company's five-year forecast of bulk and non-bulk station peak load growth, which evaluates both organic load growth and expected step load additions due to commercial and industrial activity. The Company provided annual historical substation and feeder peak demands along with summer forecasted peak load by planning area over a five-year period. This analysis was helpful to identify the year 2028 peak loads for the substations (bulk and non-bulk) that are included in the capital expansion plan. I also checked any potential additional areas for which the Company´s capital expansion plan has not yet identified or formalized a specific solution. The analysis revealed that about 32 percent of the total retail peak load in 2028 will be located downstream of bulk substations that require capacity investments during the study period to serve station peak demand reliably. The marginal bulk distribution substation cost in capacity expanding areas was multiplied by 32 percent to estimate the system-wide average cost through the five-year study period. Similarly, the marginal non-bulk distribution substation cost was separately estimated and restated to a system-wide marginal average cost. About 1.7 percent of the Company's retail peak load will be served in locations where non-bulk substations require capacity expansion to meet planning reliability standards. Both bulk and non-bulk substation system-wide average marginal costs were then combined in a single marginal station cost by voltage level. This calculation is provided in Attachment ES-MCOSS-1.

Q. How did you time-differentiate the marginal distribution substation costs?

A. I conducted a probability of peak analysis of historical hourly bulk substation data during the most recent three years (2021 - 2023) as the reference case.

Q. Please explain the computation of local marginal distribution facilities costs.

A. The MCOSS estimates the cost that is incurred by PSNH when connecting the most typical (average customer) in a given rate class to the grid. The Company is responsible for providing customer access in perpetuity, unless the site is permanently abandoned. The design demand that the Company considers when sizing a transformer and local lines is the expected long-term maximum load that the customers connected to those facilities are expected to impose on the local distribution system. This is distinctly different from the coincident peak demands considered when sizing the upstream distribution infrastructure. The local distribution facilities costs may vary depending on whether there are overhead or underground facilities, as well as whether they are single-phase or poly-phase, and customer density. PSNH service area is primarily rural and the MCOS study does not differentiate between connection costs by area type. To estimate the typical installed cost of distribution facilities, PSNH provided an extensive sample of work orders associated with customer connection jobs in the most recent three years

(2021-2023), which is large enough to be representative of the different mix of connections in the Company's service territory. The work orders included specific descriptions of the work, cost of connection before and after customer contributions, transformer capacity and number of accounts per job for each service classification. The study computes the typical per-kW installed cost of connection by customer class, net of customer contributions, and excluding the service drop which is separately estimated in the study. Appropriate weighting factors were applied in calculating a marginal facility cost by class, based on the approximate share of overhead and underground facilities, single and three-phase facilities within each customer class.

Q. Describe the method used to estimate marginal customer costs.

A. The marginal customer-related costs refer to costs unrelated to energy, peak demand, or design demand at the time of connection. These include the installed cost of the meter and service drop, customer accounts and customer service and informational expenses. Once the annualized installed costs of these assets for all customer categories are estimated, marginal O&M and marginal customer service expenses are added to obtain the total marginal customer cost by class. As part of this analysis, street lighting marginal per account costs were also computed, taking into account typical investment per fixture. The marginal customer service and informational expenses, and the marginal customer account expenses incorporate information from the last five years from FERC Form 1 data and the proforma test year. Weighting factors were obtained from the ACOSS, based on relative labor requirements and frequency of each activity by customer class. In addition, loading factors were projected based on how administration and general (A&G) expenses and general plant have historically changed with increments in O&M or plant.

IV. CLASS REVENUE REQUIREMENT ALLOCATION

Q. Are marginal costs useful in setting rate class' revenue responsibility?

A. Yes. Class revenue targets should consider the differences in the costs of providing service to different customer classes, and there is extensive literature on efficient public pricing (or utility pricing) that supports the use of marginal costs both to set marginal-cost based rate structures and to set class revenue targets. Reconciling marginal costs of service with the utility's overall distribution revenue requirement should be done in a manner that minimizes large departures from efficient electricity consumption levels by customer class. Many utilities rely on marginal cost studies for rate design, but primarily employ an ACOS approach for revenue allocation, as it is the case of PSNH. Marginal cost revenue information is nevertheless considered to estimate the relative undercollection or overcollection of revenue requirement based on proportional shares of marginal costs. It is also useful to decide on appropriate revenue relationships within a rate class.

Q. Is the use of marginal costs for revenue requirement allocation purposes supported by economic literature?

A. One of the best-known approaches is that discussed by Ramsey (1927).[1] Ramsey demonstrated that rates that raise more revenue from price inelastic customers per unit of demand will support lower cost of service and maximize customer surplus. This is because it will not lead to high price elastic customers to relocate and are less likely to also overestimate marginal cost impact of usage. In practice, utilities that use marginal costs for decisions on class revenue requirements typically use a variant of Ramsey pricing termed "equal percentage of marginal costs" ("EPMC") methodology due to lack of precise elasticity data by rate classes and legacy methods. Under the EPMC method, each rate class is allocated a share of the revenue requirement based on its share of total class marginal cost revenues. EPMC is generally used to set the starting point for class revenue targets in California and Nevada, among other states. EPMC is rarely applied without any modifications to mitigate any effects of a rate shock that may be caused by changes in bills.

Q. Did you compute marginal cost revenues by class to determine a comparison with ACOS study revenue targets and EPMC?

A. Yes. Once the marginal unit costs are estimated, I followed these steps:

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[1] *Ramsey, F.P. 1927. A contribution to the theory of taxation.* Economic Journal 37, 47–61.

1. The annual marginal (per-kWh) costs of distribution substations, the annual marginal (per-kVA, per-kW or per customer) local facilities costs, and the annual marginal customer costs by class, were multiplied by the respective customer class's billing determinants. This required using the test-year data on hourly usage by class (in the case of distribution substations), the assumed design demand (in the case of local facilities) and the test-year customer and meter numbers (for marginal customer costs).

2. The resulting marginal cost revenues by class were then added across all customer classes and compared to the total distribution revenue requirement to determine the overall distribution revenue gap.

3. The percent increase required to bring overall marginal costs revenues to revenue requirement was used to allocate the revenue gap to all customer classes.

Q. How do the marginal cost revenues compare to current rate revenues by class?

A. Table 1 below compares current distribution revenues with marginal distribution cost revenues by rate class. The data reveals that all customer classes currently pay at least the marginal cost of service, except for Rate B customers and the residential LCS class. The second aspect that I reviewed is whether each customer class currently pays in proportion to its marginal cost revenue share, relative to total marginal cost revenue, which is important as a first step, before considering differences in class demand price elasticity. When reviewing the current revenue shares by class it appears that the

Residential Rate class, the Rate GV and the Rate LG revenues are significantly misaligned with the percentage of marginal cost revenues by class. The residential rate currently contributes to 58.47 percent of the total distribution rate revenues, even though their proportional share of total marginal costs is 73.39 percent. In contrast, the largest commercial classes, rate GV and LG are paying considerably more than marginal costs of service and contribute far above its equal-proportional marginal costs, subsidizing the Residential class. This outcome suggests that a shift of cost recovery towards the residential class would be required to get closer to a more efficient allocation of embedded cost revenue requirement among customer classes, i.e., the residential class should see a larger distribution rate percentage increase relative to the overall revenue requirement percent increase to start moving revenue classes in alignment, while Rate GV and Rate LG should see a lower than average rate percent increase.

Table 1: Comparison of Current Distribution Revenues with Marginal Cost Revenues by Rate Class

Rate Class	Current Distribution Revenue	MCOS Revenue	Current Revenue Share	MCOS Share
	(000$)	(000$)	%	%
R PL+TOD	$244,615	$241,678	58.47%	72.88%
R LCS	$646	$1,572	0.15%	0.47%
RWH	$4,203	$3,258	1.00%	0.98%
GS + GS TOD	$96,493	$73,338	23.07%	22.12%
G SH	$181	$92	0.04%	0.03%
G LCS	$50	$56	0.01%	0.02%
G-WH	$136	$143	0.03%	0.04%
GV	$43,045	$4,182	10.29%	1.26%
LG	$21,077	$2,286	5.04%	0.69%
RATE B	$1,558	$2,961	0.37%	0.89%
OL	$4,277	$1,778	1.02%	0.54%
EOL	$2,062	$264	0.49%	0.08%
Total	**$418,343**	**$331,608**	**100.00%**	**100.00%**

Q. Do the marginal cost revenue results suggest similar directional changes required for rebalancing rates, compared to those resulting from the ACOS study by class?

A. Both studies reveal that the current residential rate targets are misaligned with cost causation. To achieve inter-class equity, the ACOSS revenue targets resulting for proforma test year 2023 also suggest that a large percent rate increase is required for the Residential class, equal to 59.7 percent, much higher than the average percent increase to total revenue requirement of 43.6 percent. In other words, both MCOS and ACOS studies indicate that the residential class should increase by significantly more than the overall distribution revenue requirement increase because except for the residential standard and residential TOD rate, as well as the residential LCS and Rate B, all other customers are paying more than their allocated costs and their proportional share of the marginal costs (EPMC). There are some important differences in the required revenue percent changes resulting from the ACOS study compared to the EPMC method, as demonstrated in Table 2. The EPMC assumes changes intended to achieve equal percentage shares of revenue relative to marginal costs and suggest a larger change (79 percent) for the Residential class, while the ACOSS suggests a 59.7% increase.

Table 2: Percent Changes over Current Distribution Rates as Suggested by EPMC Compared to ACOS Method Changes, Test Year 2023

Rate Class	ACOS revenue req.	% Rate Change ACOS	EPMC Rev.	% Rate Change with MCOS
	(000$)	(000$)	%	%
R PL+TOD	$390,612	59.7%	$437,739	79.0%
R LCS	$1,962	203.6%	$2,848	340.7%
RWH	$7,768	84.8%	$5,901	40.4%
GPL+TOD	$111,118	15.2%	$132,834	37.7%
G SH	$227	25.3%	$167	-7.8%
G LCS	$178	256.4%	$101	101.4%
G-WH	$223	64.1%	$259	90.6%
GV	$51,608	19.9%	$7,575	-82.4%
LG	$28,551	35.5%	$4,140	-80.4%
RATE B	$2,078	33.4%	$5,364	244.2%
OL	$4,386	2.6%	$3,220	-24.7%
EOL	$1,913	-7.3%	$477	-76.9%
	$600,624	**43.6%**	**$600,624**	**43.6%**

Q. What are the main takeaways from this comparison?

A. Full change towards achieving EPMC is not recommended in this case to avoid large unacceptable bill impacts, but it is helpful to see the main directional changes from EPMC. Accounting balances do not include sufficient detail to appropriately apportion the components of plant that are in fact used to serve the larger, primary commercial customers. This explains why it is generally the case that more costs are allocated to large commercial customers under an ACOS compared to a MCOS study. EPMC allocations are on the other hand based on a more granular analysis regarding the use of different components of the distribution system by voltage level as well as by time of day and season. For example, in the case of LG customers, the ACOSS allocates plant and O&M expense for feeders below the 34.5-kV level, even though these customers are connected at or above that level. The smaller rate classes are also particularly sensitive to changes in revenue allocation method. The Company has adopted embedded cost study results as the guide to evaluate revenue requirement allocation to classes, moderated to minimize bill impacts. Overall, the direction of these decisions is generally consistent with what a marginal cost-based approach suggests after considering gradualism, or the avoidance of unacceptable large bill impacts.

V. RECOMMENDATIONS ON RATE STRUCTURES

Q. What key rate design changes are suggested by the results of the MCOS?

A. The main rate design implication from the 2024 MCOS study is that customers are paying significantly more than the underlying marginal costs in usage charges, across the board. This conclusion is demonstrated by the comparison of marginal unit cost per kW or per kWh with the existing charges. Currently, efforts are being implemented across the country to reduce the over-reliance of fixed distribution cost recovery through usage charges and increase fixed charges to increase equity across customers within the class. Such rate rebalancing process also reduces the distortion in price signal (i.e., increments of usage lead to a lower grid cost impact than the existing kWh charges appear to indicate) and the existing cross-subsidies within the class (higher usage customers disproportionally paying more than cost of service). A rate rebalancing that follows the underlying marginal cost structure is also conducive to lower costs of achieving decarbonization and electrification of space heating and transportation in the future.

Q. How can utility rates be structured to more appropriately reflect marginal costs?

A. Rates ideally would have a multi-part structure that preserves economically efficient price signals for the key components of the service that influence consumption patterns, that is, volumetric or per-kW charges. These should be kept as close as possible to the underlying, near-term marginal costs. PSNH's marginal costs associated with peak load growth are relatively low on a system-wide average basis over the five-year planning period. The current per-kWh charges in PSNH's distribution rates exceed the per-kWh marginal costs of upstream distribution service. Ideally, an efficient distribution rate would be a 3-part rate that reflects the underlying structure of marginal costs of service, but this is not always feasible.

Q. Please explain what you mean by a rate that mimics the marginal cost structure.

A. To follow cost causation based on the estimated marginal distribution unit costs on a system-wide basis, the rate would have the three components that follow the marginal cost drivers of each component of service:

- Time-differentiated per-kWh charges that recover marginal distribution substation and upstream feeder costs (the per-kWh charges may also be replaced with time-differentiated metered per-kW charges).
- A monthly fixed customer charge that recovers marginal customer-related costs, including the monthly costs of the meter, service drop, customer service and account expenses.
- A monthly distribution facilities charge based on customer's maximum capacity required to meet long term maximum demands and recovers the marginal costs of local facilities (local primary lines, transformers, secondary lines). Recovering marginal facilities costs in full through a monthly fixed charge, calculated on the basis of the class average design demand, is also appropriate in lieu of a facilities charge per kW of design demand, when such charge is not administratively feasible.

Q. Do the Company rate design changes for this GRC follow the principles that you outlined above?

A. Yes. The Company has increased both fixed and usage charges of all customer classes as part of the overall revenue increase. The Company partial increase in the customer charges, ensures that the fixed charge recovers the marginal customer cost for the residential class and a portion of the local facilities costs. This is the correct approach consistent with MCOS and ACOS study results and with best practice ratemaking objectives as I discuss in this testimony. Any need to increase revenue above marginal cost would ideally be channeled through increases in the fixed components of the rate, and the least price elastic component is the fixed charge, followed by any facilities charge if one was in place. The proposed residential customer charge is $19.81 per customer, which recovers the monthly marginal customer cost of $18.14 plus a small share of the local facilities costs. This proposal is sound and consistent with rate design principles of efficiency and equity. It avoids further exacerbating the usage charges away from the underlying marginal costs, which can overly discourage usage of the grid when there is ample capacity in the grid. It also helps reduce, and partially mitigate, inequity between high and lower than average usage customers. This is particularly important at a time where the low-usage segment of the customer base is increasingly less reflective of low-income customers, as it includes accounts for vacation homes and for customers that have adopted solar PV and lowered their monthly energy usage. There is no economic value created when overcharging for usage in hours when price is several times higher than the cost, and it can accelerate adoption of uneconomic DERs that is not beneficial to the system or other customers.

Q. Did you evaluate the suitability of the existing time of use periods?

A. Yes. Time-differentiation for distribution rates must keep in mind the system-wide distribution hourly marginal cost patterns. As I explained above, I conducted a distribution probability of peak using the most recent years' hourly loads at the bulk distribution substation level. For residential customers, the current peak period currently begins at 1 pm and ends at 7 pm. My analysis revealed that the period includes the core, critical three summer peak hours on the grid, which are currently 4 pm to 7 pm. However, there is significantly lower probability of peak at any afternoon hours prior to 2 pm and increased probability of peak from 6 pm to 8 pm, compared to the findings of my TOU analysis in the prior MCOS (2019 GRC) which suggests that a modification of TOU periods would increase cost-reflectiveness of the peak distribution rate. To confirm this I tested a scenario that includes the expected hourly impact of solar PV additions in the NH service area by year 2026, based on ISO-New England forecasted PV in New Hampshire. These modified hourly load profiles were used to re-run a probability of peak that provides a forward-looking perspective of system load profiles as opposed to relying exclusively on historical recent hourly load profiles. PSNH may experience a relatively modest growth of PV. Nevertheless, such analysis reinforced the direction of the peak periods moving to later in the afternoon. A start of the peak period at 2 pm would recognize the impact of solar PV penetration and be consistent with the reduced probability of peak in early to mid-afternoon. It will also be important to add the weekday hour 7 pm to 8 pm as more customers enroll in the TOU rate. For the time being, it is not imperative to make a change in the peak period given that there are currently less than 40 customers enrolled in the Residential TOU rate. Retaining 1 pm does allow to consider areas of the service territory where substations still experience high loads earlier in the day. The Company has factored this into its decision not to change the peak period at this time.

Q. Is the time of use differentiation necessary outside of the summer months?

A. A decision of keeping the same TOD charges year-round does not strictly align with the underlying seasonality in peak-related costs. About 90 percent of the annual probability of peak falls in two months, July and August, and the remaining 10 percent falls in the months of June and September. Only a small number of bulk substations, less than 10 percent of the total station capacity experience a peak load in the winter months of December or January, and there is higher substation carrying capability in the winter relative to the summer. The Company targets and evaluates summer peak load to screen the need for expansion. Nevertheless, continuing with year-round distribution TOU periods may be advisable when considering growth of DERs and impact on the distribution station load profile in the future. In the longer-term, additional electrification will potentially shift more cost responsibility to the winter evening hours.

Q. Did you compare the current rates with the marginal unit costs that would follow an efficient marginal cost structure?

A. Yes. Table 3 shows marginal unit cost for each component of the service using the existing time of day periods and the year-round construct of the existing rates. Marginal local distribution facilities costs are shown separately, in two alternative ways – per customer and per kW of monthly design demand or contract demand. Marginal primary costs are also shown in two alternative ways – per kW of monthly metered demand and per kWh of usage. The marginal unit cost figures have not been marked up to reconcile with the class revenue targets, but they are useful to assess the efficiency of the price signals in the current rates.

Table 3: Summary of Marginal Unit Costs by Rate Class

		Local Distribution Facility Marginal Costs		Primary Distribution Marginal Cost (*Existing TOU Periods*)		
		Per cust.	Per kW		Demand	Energy
Service Classification	Customer Cost	Monthly Facilities Cost per Customer	Montly per Design Demand kW	TOU Period	Per-kW of Metered Max Demand	Restated as $/kWh
	($/Cust./mo)	($/Cust./mo)	($/kW-mo)		($/kW-mo)	($/kWh)
R-P&L	18.14	24.76	3.30	All	1.270	0.00174
R-OTOD	25.73	33.01	3.30	On-Peak	1.045	0.00837
				Off-Peak	0.225	0.00037
R-C-WH	2.96	2.64	3.30	All	1.270	0.00174
R-LCS	3.52	8.25	3.30	All	1.270	0.00174
R-UC-WH	2.91	2.64	3.30	All	1.270	0.00174
GS-P&L-P1	19.96	56.12	3.30	All	1.270	0.00174
GS-P&L-P3	36.90	156.57	1.91	All	1.263	0.00173
GS-OTOD-P1	26.04	56.12	3.30	On-Peak	1.167	0.00431
				Off-Peak	0.103	0.00022
GS-OTOD-P3	37.01	156.57	1.91	On-Peak	1.161	0.00429
				Off-Peak	0.102	0.00022
GS-UC-WH	4.48	2.31	3.30	All	1.270	0.00174
GS-LCS-P1	4.99	15.75	3.30	All	1.270	0.00174
GS-LCS-P3	11.62	9.11	1.91	All	1.263	0.00173
GS-SH	3.81	13.40	3.30	All	1.270	0.00173
GV	89.78			All	1.263	0.00173
GV-B (<115 KV)	89.76	na	n/a	All	1.263	0.00173
LG	99.23	na	na	All	1.263	0.00173

Q. Overall, what is your conclusion on PSNH's proposed rate designs as proposed in this proceeding?

A. PSNH's proposed rate designs recognize that rates should gradually be rebalanced to seek improved economic efficiency and equity, while considering and avoiding extreme bill impacts due to the need to recover investments. I find that the Company's approach in increasing all the rate components for all classes, instead of recovering the full revenue increase entirely on the volumetric charges has merit and it will ultimately lead to lower cost of service for the average customer. Incremental usage does not lead to a high cost for the Company as most of the distribution grid can accommodate that load in many hours of the year, and currently incremental usage leads to a disproportionate increase in the customers' electricity bill. I would recommend at this time gradually increasing customers' distribution fixed charges towards the sum of monthly marginal customer cost plus facilities costs, taking into account bill impacts.

Q. Does this conclude your testimony?

A. Yes, it does.