STATE OF NEW HAMPSHIRE

BEFORE THE

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

DOCKET NO. DE 19-057

REQUEST FOR PERMANENT RATES

DIRECT TESTIMONY OF

AMPARO NIETO

Marginal Cost of Distribution Service Study and Implications for Rate Design

On behalf of the Public Service Company of New Hampshire

d/b/a Eversource Energy

May 28, 2019

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Attachment

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

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I. INTRODUCTION

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

A. My name is Amparo Nieto. I am a Senior Vice President at Economists Incorporated ("EI"). My office is located at 101 Mission Street, San Francisco, California.

Q. On whose behalf are you testifying in this rate case?

A. I am testifying on behalf of Public Service Company of New Hampshire d/b/a Eversource Energy ("PSNH" or the "Company").

Q. What is the purpose of your testimony?

A. I recently completed an updated electricity marginal cost of distribution service study ("MCOSS") for PSNH. This testimony describes the method used, summarizes the results by rate class and discusses the main implications for evaluating the efficiency of existing PSNH's distribution rate design and potential revisions. The marginal cost results are useful to inform the direction of the changes that PSNH may adopt to improve existing distribution rates, both with regard to structure and price levels of specific components.

The MCOSS is also helpful to inform class revenue targets that would be consistent with marginal cost principles. The 2019 MCOSS results has been filed in this proceeding and are included in Attachment 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 Allocated Cost of Service Study ("ACOSS") for the Company as required by the Commission and provided separate testimony on that topic. My ACOSS testimony includes further information on my professional background and qualifications.

Q. How is your testimony organized?

A. My testimony is organized as follows.

- In Section II, I summarize the findings of the MCOSS and the key implications for rate design.
- In Section III, I discuss why it is important to take into account marginal costs in distribution ratemaking.
- In Section IV, I discuss the specific marginal distribution cost methods that I employed to estimate PSNH's marginal costs.
- In Section V, I explain my review of class marginal distribution cost revenues, comparing them with the current rate revenues and ACOSS class revenue requirements and discuss the main findings from this comparison.

- In Section VI, I discuss the distribution rate structures that would more closely follow the marginal cost structure of the Company's distribution service, as well as the changes to specific rate components that would enable a more efficient use of the distribution system via more cost-reflective price signals.

- In Section VII, I provide conclusions on my review of PSNH's final rate designs.

II. SUMMARY OF TESTIMONY

Q. Please summarize the key findings and recommendations of your direct testimony regarding the marginal cost results.

A. The MCOSS includes an estimate of all of the elements of marginal distribution costs of service by taking into account the specific characteristics of PSNH's distribution system and its customers. The marginal cost of electricity delivery represents the incremental cost incurred by the Company to serve the next unit of demand at any given point in time, voltage level and location. The incremental cost incurred by the Company to provide customer access to the grid as well as other customer-related services are also part of the marginal costs of distribution service. PSNH's MCOSS, as summarized in Attachment MCOSS-1, reveals that marginal upstream distribution costs are currently very low on a system-wide basis, given the relatively small amount of planned capacity expansion needed to meet station peak load growth over the study period 2020 through 2024. The peak load served by the identified substation projects represent only about 20 percent of the overall forecasted retail peak load in year 2024. This means that approximately 80 percent of the system will not require any upstream distribution capacity upgrades to reliably meet the expected peak load as per design requirements. The MCOSS also demonstrates that there are two different cost drivers for upstream distribution and the more local distribution facilities.

Q. Please summarize the key findings and recommendations of your direct testimony regarding use of marginal cost results for revenue allocation.

A. The Company's rates have been traditionally set on the basis of allocated cost of service studies. As I discuss in Section V of my testimony, a MCOSS-based revenue requirement allocation is more likely to lead to a welfare-maximizing pricing solution as compared to an ACOSS-based approach. The Company recognizes that there is a merit in using the findings of MCOSS in the rate design process, but it is proposing to continue relying on ACOSS as a reference for setting class revenue targets. Departing from the ACOSS method in the current rate case would result in major rebalancing among rate classes, further beyond the re-balancing already suggested by the 2019 ACOSS. In particular, the residential class would see a larger revenue target increase, which would be countered by significantly large reductions in revenue targets to other rate classes. These class revenue target shifts combined with a 19.98 percent increase in overall distribution revenue requirement would produce too large bill impacts. I find to be a reasonable concern. PSNH is not proposing any structural changes for its main rate classes in this proceeding, which would have enabled a smoother transition to a marginal cost-based revenue requirement approach. I recommend that the Company revisits a marginal cost-based revenue target approach at a later stage. In the meantime, it is still important to review the current marginal cost revenues by rate class and establish whether each class is paying at least marginal costs plus a share of the distribution sunk costs.

Q. Please summarize the key findings of your direct testimony regarding use of marginal costs for rate design.

A. This testimony describes what an efficient rate structure would look like if the Company were able to revise existing rates so that all customers could face a more efficient price signal, through the use of charges that more closely reflect the underlying distribution marginal costs. My main recommendations are summarized below.

- To follow cost causation, and given the low marginal distribution costs on a system-wide basis, it is essential to shift a share of the current recovery of distribution sunk costs away from the per-kWh or demand charges and towards customer charges for most customer classes.

- Introducing a monthly distribution facility charge on a per kW of customer maximum design (or connected) demand is useful to better align the cost driver of local facilities (transformers, local primary conductors and secondary voltage lines) to the method of recovery. This approach recognizes the more fixed nature of the transformers, which are sized based on the maximum demands that the local customers can be expected to impose over the service life of the facilities. These costs are more appropriately recovered using the customer's estimated design or contract demand as opposed to using actual metered demand or kilowatt-hours in a given month, to limit inter and intra-class subsidies.

- If introducing a contract demand or facilities charge is not feasible for a given rate class, I recommend recovering the marginal facilities cost estimated for the average customer as a monthly fixed charge, after appropriate consideration of bill impacts. The sum of monthly marginal customer and facilities cost should guide the required customer charge differential for one phase and three-phase customers within a given rate class.

- Ideally, all distribution rates would be seasonally differentiated, with a two-month summer season (July and August) to signal the months with the highest capacity constraints, or a four-month season (June through September) if switching to two-months would produce excessive bill impacts.

- Time-differentiation for distribution rates must keep in mind the system-wide distribution hourly marginal cost patterns. The current peak period should be shortened, and the peak/off-peak charge differential should be reduced.

Q. Are PSNH'S proposed rate changes supported by the findings of the MCOSS?

A. PSNH's distribution rate design proposals represent a conscious effort to moderate bill impacts resulting from the overall class revenue requirement increase, while still making an effort to adopt a number of measures that aim to improve the efficiency of rates, as informed by the MCOSS findings. The Company has increased the fixed charges of all customer classes as part of the overall revenue increase, to bring them closer to marginal customer cost in most cases, or to the sum of marginal customer and facilities costs, in the case of residential and commercial time-of-day rates. The Company also has ensured that the customer charges of the general service single phase and three phase customers are set to reflect the single-phase versus three-phase marginal customer and facilities cost relationship. A decision to modify the peak period in PSNH's existing Time of Day (TOD) distribution rates is pending given the Company's time of use pilot that the Company is planning to launch in the near term. Other factors such as introducing seasonality in rates will be addressed as more data by rate class is developed.

III. DEFINITION OF MARGINAL COSTS AND THE THEORY SUPPORTING USE OF MARGINAL COST FOR UTILITY RATES

Q. What is marginal cost?

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 absence of market failures such as externalities, or economies of scale, the market clearing price will equal the social marginal cost of service. This outcome is economically efficient because it leads to a level of production (demand) that maximizes the sum of producer profits and the consumer surplus (the consumer's valuation of the product net of the price paid for it). In presence of natural monopolies such as regulated distribution utilities exhibiting large economies of scale, marginal cost continues to be important to signal the cost implications of increasing amounts of demand. Customers make decisions based on how the marginal increase in the bill compares to the value they obtain from the additional use of electricity.

Q. What are the benefits of setting distribution rates that closely reflect the marginal grid costs?

A. Aiming to achieve economic efficiency in the use of the distribution grid requires that the variable component of the delivery rates reflects as close as possible the marginal costs of providing service at any given time. If the price for additional usage of electricity reflects marginal costs, the utility will only plan for system upgrades to meet peak load growth when justified by the consumers' willingness to pay. In this scenario, the pattern and cycles of capacity expansion, and subsequently the cost of service, will be more aligned with how customers value reliable delivery of electricity. To maximize the efficiency gains from rate reforms, rates also need to inform the relative level of marginal cost differentials by time of day and/or season, and difference in marginal cost of service by voltage service. This is particularly important because it will lead customers to make decisions that align customer load reductions with system savings. Optimal utilization reduces unnecessary financial burden on the utility and ultimately on the rates paid by utility customers. It also reduces inter and intra-class cross subsidies.

Q. How do marginal cost-based rates affect intra-class equity?

A. If the variable rate is higher than the underlying marginal cost the quantity demanded will be too low as compared to the optimal level – additional electricity could have been served at a cost that would be lower than its value to the customer. Rate structure also needs to be aligned with marginal cost structure. If costs that do not vary with usage are recovered in a per-kWh charge, a high-load factor customer will pay more towards recovery of sunk costs, even though the customer may not impose higher costs than a lower load factor customer within the same class. The lack of time-differentiation or poorly designed periods may exacerbate this problem. A distortion also occurs in the case of prices that are set below the underlying marginal costs. In both cases there is a net deadweight loss that has both efficiency and equity implications.

Q. Are marginal cost price signals important for efficient adoption of DERs by customers?

A. Yes. Customers who face marginal cost-based price signals will decide to self-generate only when the cost of doing so is lower than the cost of having the utility delivering electricity to customer premises. Marginal cost-based rates are more likely to send economically efficient price signals as to when and where it is valuable for the system that the customer invests in energy storage along with rooftop solar or another form of distributed generation. Traditional net metering billing practices combined with simplified rate structures that often do not follow marginal cost structures are likely to produce the wrong incentives to adopt DERs. If the energy or demand charges are not marginal cost-based, in either regular or standby rates, customer-owned storage may be installed at a cost that exceeds the marginal cost of using the utility's resources. This outcome is not only inefficient but inequitable. Such inequity is exacerbated as self-supply alternatives available to consumers continue to grow, such as rooftop solar and other DER.

Q. What is the right time framework to estimate marginal costs of distribution service?

A. The marginal cost of securing delivery of power through the distribution grid for an additional kW at a given hour will vary depending on the amount of notice assumed, and the ability of the utility to respond to the change in usage. In the short run, these marginal costs involve mainly distribution losses and potentially shortage costs, if the transformer or grid does not have sufficient capacity to accommodate the new load. The value of the foregone electricity to the customer for whom the service has been interrupted represents the short-run marginal ("shortage") cost. This pure short-run marginal cost-scenario is not helpful to set utility rates, because the utility rates are set in advance for a number of years and, unless some forms of dynamic pricing, do not change in real-time conditions. For purposes of setting rates, the MCOSS needs to adopt a longer time framework for measuring marginal distribution costs, recognizing that the utility will plan the system as required in response to an anticipated unit of additional usage, which in some locations may involve capacity additions.

IV. METHOD USED IN PSNH'S MCOSS

Q. Please describe the main elements of the MCOSS that you prepared for PSNH.

A. The MCOSS as filed by PSNH was a forward-looking exercise over a five-year horizon. This timeframe represents a good balance between the advance period that PSNH typically needs to formalize distribution investment plans (two to three years) and the timeframe needed to obtain a more stable price signal. 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 enough 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 and a system-wide average marginal cost is calculated for rate setting purposes. Marginal operation and maintenance ("O&M") expenses, and loading factors were included in the final annual cost. The MCOSS summarizes hourly marginal bulk and non-bulk distribution station costs by pricing periods suitable for the design of time of use ("TOU") and seasonal tariffs.

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 explain what criteria you used to select distribution station projects suitable for inclusion in the MCOSS.

A. The marginal high-voltage distribution cost analysis builds upon a review of the Company's budgeted investments in both bulk and non-bulk substations during the upcoming planning period (2020-2024). The first step was to identify the relevant investments associated with planned bulk station upgrades or replacement projects. The criteria involved selection of projects that could potentially be avoided if the particular substation experienced peak load reductions. The majority of the distribution projects involve replacement of existing substation transformers with one (or two) larger transformers. They may intend to address overload conditions, and some may be driven by upcoming additions of industrial or commercial load, and/or by the need to offload nearby substations. PSNH's capital plan foresees station upgrade investments needed to ensure that peak load will be meet under both base case (N-0) and contingency scenarios (N-1). The Company's five-year capital plan includes upgrades for a portion of the bulk substations that are falling short of meeting the N-1 planning design criteria. N-0 projects inherently have a higher priority due to the need to have the capability to serve customer load under normal (base case) conditions.

Q. What investments did you exclude from the marginal substation cost analysis?

A. I excluded projected investments associated with retirement of obsolete equipment, since these are unlikely to be impacted by changes in the load. The MCOS study also excludes investments that are 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 did your analysis of bulk station load forecasts on a system-wide basis reveal?

A. I reviewed the Company's five-year forecast of bulk station peak load growth, which takes into account an assessment of both organic load growth and expected step load additions due to commercial and industrial activity. PSNH distribution planners decide the timing of expansion of a station under N-1 planning criteria when the station is loaded at or above 75 percent of its normal (nameplate) rating, since this level of load begins to compromise the station's long-term emergency rating. The emergency rating reflects the load that can be sustained temporarily, i.e., for a limited number of hours before voltage instability (or ultimately loss of load) occurs. Using the N-1 design criteria, I estimated the share of the bulk distribution system that is likely to require expansion as new load materializes using station peak forecast over the five-year period. The analysis reviewed that the majority of bulk stations will have ample capacity to serve peak demand during the study period.

Q. How did you estimate the marginal non-bulk substation cost over the full five-year planning period?

A. PSNH's capital plan includes an estimated amount of peak-load related investment in non-bulk distribution stations over the period 2020-2024, albeit it is not based on identified locations. The MCOSS relied on a forecast of non-bulk station peak loads over the next five years and compared them to the station long-term emergency ratings to identify potential investment needs at specific locations. These forecasts used the average regional peak load growth rates, rather than relying on station-specific projections since they were not available. PSNH, like many other US distribution utilities, predicts non-bulk station investments driven by peak load growth with sufficient confidence within a timeframe of two to three years. Projection of non-bulk expansion investments further into the future tend to be less certain than those at the higher voltage stations. Decisions about ultimately expanding a station transformer are not formalized until the station peak load begins to reach its long-term emergency rating. My review of these stations found that most of PSNH's non-bulk distribution system has more than sufficient capacity to meet expected peak load over the study period. The few capacity constraints that the MCOSS identified are largely expected to be addressed by switching load to a neighbor station with sufficient spare capacity in the near term. These short-term measures defer the need for expanding the substation transformer at least for the next five years examined in the study.

Q. Please explain the method you used to recognize geographical differences in the computation of a system-wide marginal cost estimate for bulk and non-bulk stations.

A. PSNH's standard distribution rates do not vary by geographical location, thus, the MCOSS calculates a system-wide average to be useful for rate design. The estimated marginal station cost per-kW of peak load was weighted by the retail peak-load share corresponding to those stations that are due for expansion. A zero marginal cost is implicitly assumed for any areas not likely to require capacity investments. This represent about 80 percent of the PSNH's retail load in the case of bulk stations. An equivalent approach was used to estimate a system-wide marginal cost for non-bulk stations. About 95 percent of the areas served by non-bulk stations will not need to be upgraded for peak load reasons in the 2020-2024 timeframe. The marginal non-bulk per-kW cost was further adjusted to recognize that the majority of PSNH's retail customers (or 83 percent of the total load) are not served from these lower voltage substations but from smaller primary transformers.

Q. Did you use any other adjustment factor to marginal investment in distribution substation?

A. In the case of bulk stations, converting the marginal investment per kW of capacity to a dollar per-kW of peak load carrying capability required adjusting the unit cost by the 75 percent planning design factor. The marginal station cost by voltage level, both on a system-wide and on a locational basis (averaged for all the areas of expansion) are provided in Attachment MCOSS-1.

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

A. The MCOSS includes an analysis of historical hourly bulk substation data during the last four years (2015 - 2018) which determined that the majority of the stations are more likely to experience their peak load between 11:00 am and 7:00 pm on summer weekdays, and primarily in July and August. The MCOSS developed allocation factors based on relative probability of distribution peak to allocate the annualized marginal costs to peak and off-peak periods. The current on-peak period in TOD distribution rates is defined as 7:00 am to 8:00 pm on weekdays, year-round. This peak period is too broad and fails to effectively signal the hours with the highest cost of distribution service. As informed by the MCOSS, there is only a subset of those hours that are responsible for the investment in distribution substation and primary feeder infrastructure.

Q. What method did you employ to estimate the marginal primary distribution trunk-line feeder costs?

A. The Company's capital plan for the next five years does not include primary trunk line feeder expansion related to meeting peak load, therefore the marginal cost for that component is zero.

Q. Please explain your 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 to provide customer access in perpetuity, unless the site is permanently abandoned. The design demand that the Company considers when installing a transformer and local lines is the 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 that are considered when designing plant at the upstream distribution voltage levels.

The facilities cost approach estimates the current opportunity cost or "rental" value of the average customer connection in the class. The study identifies the current installed cost and size of secondary transformer, primary lines, and/or secondary lines for different customer configurations in a rate class, net of up-front customer contributions. The marginal local distribution costs may vary depending on whether there are overhead or underground facilities. Single versus three-phase connections also have different connection costs. 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 (2015-2017). I considered the sample to be large enough to be representative of the entire service territory. The work orders included specific descriptions on the work, cost of connection before and after customer contributions, transformer capacity and number of accounts per jobs for each service classification. I computed the typical per-kW installed cost of connection by customer class, after taking into account customer contributions and using appropriate weighting factors where corresponding for overhead and underground facilities, single and three-phase facilities within each customer class.

Q. Why are the investments in distribution facilities not related to changes in on-going energy usage?

A. The utility will typically invest in distribution facilities when a customer is initially connected to the grid, and again whenever the facilities are replaced at the end of their service life. At that point, the cost of the new transformer may have changed due to inflation, technological change, or design standards. It may also occur, albeit less frequently that a significant change in the customer mix at the specific site has taken place, due to construction of data intensive buildings in the premise or other factors. In some cases, the customer may install limited-load equipment or equivalent measures that might warrant a lower level of design demand. A customer may be entitled to a lower than the standard average design demand in cases where the utility has installed an automated load control system or other energy-efficiency measures that permanently reduce its maximum demand.

Q. Describe your method to estimate marginal customer costs.

A. The third part of the study involves analysis of the marginal customer-related costs, i.e., those costs unrelated to energy or demand. These include the installed cost of the meter and service drop, customer accounts and customer service and informational expenses. Once the annualized installed cost of these assets for all customer categories are estimated, marginal O&M and marginal customer service expenses are added to obtain total marginal customer costs. As part of this analysis, street lighting marginal costs are also computed, taking into account typical investment per fixture.

Q. What elements of the study relied on historical information?

A. The components of MCOSS that rely on historical information include the marginal distribution O&M expenses, the marginal customer service and informational expenses, and the marginal customer account expenses. Marginal customer account and service expenses represent the cost of adding and maintaining a new customer account. These costs were estimated from a review of dollars of expense per unit of capacity or customer for the last five years from FERC Form 1 data. 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.

V. USE OF MARGINAL COSTS FOR CLASS REVENUE REQUIREMENT ALLOCATION

Q. What cost allocation approach should be used in setting rate class' revenue responsibility?

A. Class revenue targets should consider the differences in the costs of providing service to different customer classes. 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. Due to the economies of scale inherent to a natural monopoly such as that of the utility distribution business, rates that are set equal to marginal costs will not match the utility's revenue requirement and an adjustment will be needed to ensure that the utility recovers a fair return on required investments and operational costs. 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 to different degrees on marginal cost studies for rate design but not for revenue allocation. The most commonly employed cost of service studies by utilities for utility revenue allocation purposes in the U.S., and one adopted by PSNH is all prior rate cases is the ACOS or embedded cost approach. Any change in the method to allocate revenue responsibilities across customer classes may entail efficiency gains but also income distributional impacts that would need to be considered.

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 to maximize social welfare, those consumers with relatively more inelastic demands for a particular good will need to pay a higher markup above marginal cost as compared to less price elastic consumer types to make the utility whole. Price elasticity of demand is defined as the percentage change in quantity demanded divided by the percent change in price. All other things equal, rates that follow the Ramsey inverse-price elasticity method raise more revenue from price inelastic customers per unit of demand, because this minimizes total deviations from the optimal consumption level that would occur in absence of market failures (if customers could just pay marginal costs).

Q. Do U.S. utilities use the Ramsey approach in setting marginal cost-based revenue allocations?

A. 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 however, rarely applied without any modifications to it based on available qualitative evidence of customer reaction to prices, or to mitigate any effects of

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

a rate shock that may be caused by changes in bills. This is because otherwise, the most price-inelastic rate class would receive the same mark-up as classes with lower price-elastic customers, even though they are likely to respond differently to the price changes, leading to a loss in consumer surplus. Lower marginal cost mark ups for customers with high price demand elasticity may also be necessary to avoid an uneconomic bypass of the grid. It is inefficient that customers largely deviate from the usage that they would have made of the grid if rates were set at marginal costs.

Q. Is it possible to set efficient rates using an ACOS-based revenue requirement allocation?

A. To avoid cross-subsidization, marginal costs should ideally be used as the starting point of the rate class revenue target, i.e., making sure that no rate class pays below the marginal costs of serving them. When using an embedded cost of service as the basis to set class revenue targets, particular attention should still be paid to whether the resulting class targets always ensure that all customers pay at least their marginal cost of service. In developing the ACOSS, I introduced modifications to the allocators to the extent that it was feasible to keep in mind marginal cost principles. This moves the class revenue targets in an appropriate direction, relative to efficient allocation of rates, although not enough to make the two methods comparable. An ACOS-based cost allocation may in some cases give less room to undertake the appropriate split of cost recovery between fixed and energy charges. In other words, rate design may be more constrained in its ability to send an efficient price signal (closer to marginal cost) in the volumetric portion of the rate. For example, the ACOSS may suggest to allocate more costs to demand charges even if this overestimates the incremental cost impact of an increase of kW by the customer. The ACOSS also is limited because it relies on accounting information and is not granular enough to establish time-differentiation or cost differentiation by voltage level.

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:

1. The annual marginal (per-kWh) costs of distribution substations, the annual marginal (per-kVA, per-kW per customer) local facilities costs, and the annual marginal customer costs by class, were multiplied by the respective customer class' 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. According to my calculations, all customer classes are currently paying at least their marginal cost of service. This is the first condition for efficiency. However, the current revenue shares by class are misaligned with the percentage of marginal cost revenues by class. While revenue requirement split across rates does not need to exactly keep the same proportions of class marginal cost revenues, they should ideally only depart from those proportions in inverse relationship to their price demand elasticity. Table 1 below compares current revenues with marginal cost revenues by rate class. The residential rate currently contributes to 56.32 percent of the total distribution rate revenues, even though their proportional share of total marginal costs is 68.60 percent. In contrast, all other major rate classes, i.e., rate G, GV revenues are in close proportion to their share of overall marginal costs, albeit slightly higher. The LG rate contributes far above its marginal cost revenues. This outcome would suggest a shift of cost recovery towards the residential class would be required for a more efficient allocation of sunk costs among customer classes.

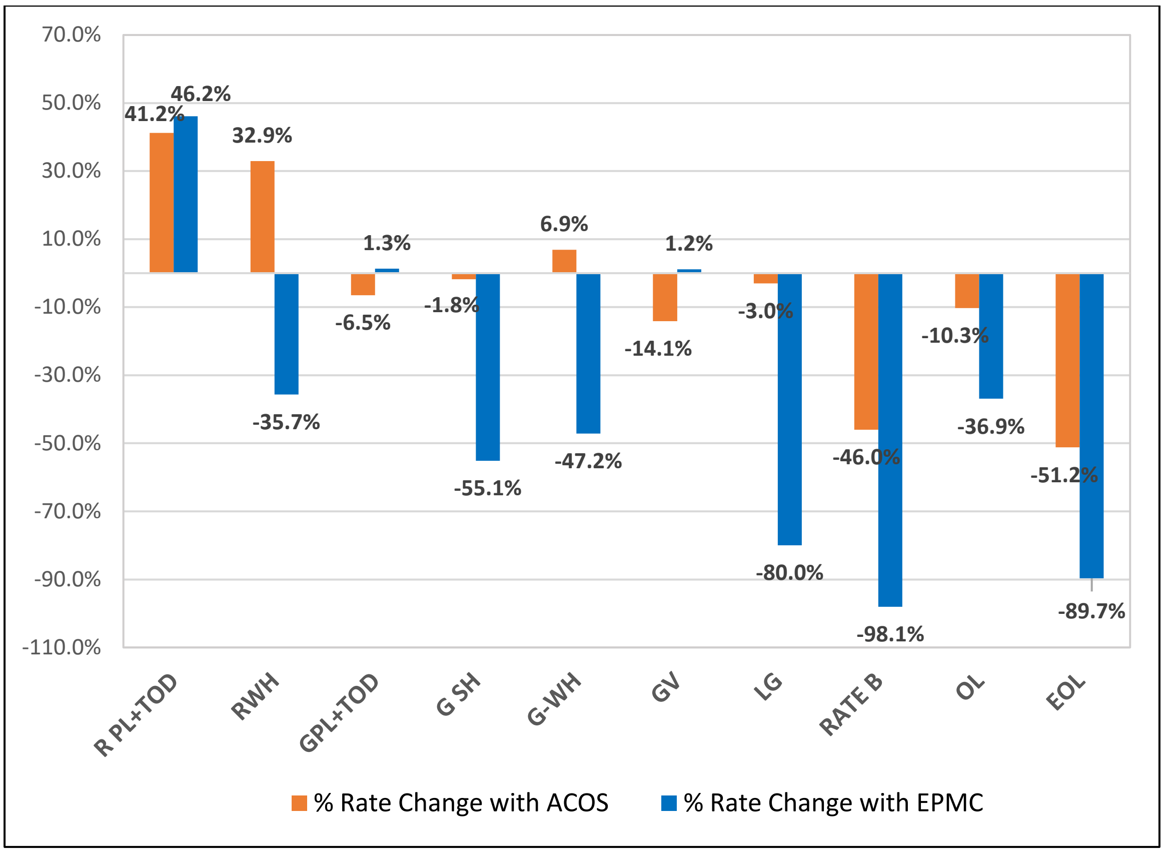
Table 1: Comparison of Current Distribution Revenues and Marginal Cost Revenues by Rate Class

Rate Class	Current Revenue	MCOS Revenues	Current Revenue Class Share	Marginal Cost Class Share
	(000 $)	(000 $)	(%)	(%)
R PL+TOD	$197,030	$169,601	56.32%	68.60%
R LCS	447	287	0.13%	0.12%
RWH	4,188	1,587	1.20%	0.64%
GPL+TOD	83,801	49,997	23.95%	20.22%
G SH	201	53	0.06%	0.02%
G LCS	29	25	0.01%	0.01%
G-WH	137	42	0.04%	0.02%
GV	36,149	21,536	10.33%	8.71%
LG	18,814	2,219	5.38%	0.90%
RATE B	1,489	17	0.43%	0.01%
OL	4,501	1,672	1.29%	0.68%
EOL	3,077	187	0.88%	0.08%
Total	**$349,862**	**$247,223**	100.00%	100.00%

Q. What are the required rate changes required by EPMC and how it would compare with ACOS-based rate changes by class?

A. The ACOSS revenue targets for proforma test year 2018 suggest a comparable percent change is required for the Residential rates, to improve inter-class equity. Both studies suggest that under each method, the residential class should increase by more than the overall distribution revenue requirement increase. The EPMC suggests that all customers except for the residential standard and TOD rate are paying more than their fair costs and should see a reduced rate. However, the ACOSS offer very different result for all other rate classes, in particular the LG rate and the smaller rate classes, as compared to the EPMC-based allocation. The smaller rate classes are particularly sensitive to changes in revenue allocation method. Figure 1 below illustrates the impact in terms of required distribution rate changes under each method.

Figure 1: Percent Changes over Current Distribution Rates as Suggested by EPMC and Compared to ACOS Method for Test Year 2018



Q. What are the main take-aways from this comparison?

A. A number of factors are behind the large differences in results. Marginal costs are forward looking, while embedded costs are, to a large extent, backward looking. Marginal costs are driven by current technology and design criteria, while the ACOSS uses accounting costs that are a function of prior planning practices and are heavily influenced by past regulatory policies. In addition, the EPMC allocations are based on a more granular analysis as to 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. They also receive an allocation of sunk costs even though the marginal cost of primary feeders is zero for the upcoming planning period. Both studies reveal that the current rate targets are misaligned with cost causation.

VI. RECOMMENDATIONS ON RATE STRUCTURES

Q. What goals are served by using marginal costs in ratemaking in addition to sending efficient price signals?

A. The efficiency goal in utility rate designs need to be balanced with equity, rate stability, customer acceptance (avoidance of rate shock), and price understandability goals. The goal of 'fairness' in utility pricing sometimes is equated with the protection of low-income users, but this income redistribution related goal should not be ideally addressed through standard rate design, to avoid distortion of the price signal that all customers see. A plan to gradually increase small customers' distribution fixed charges to the level of marginal customer costs would give more efficient signals about the true cost of being connected to the system and would mitigate subsidies to low-use customers from high-use customers. Equity may also be interpreted as ensuring that all customer classes are paying at least the marginal cost of the service they receive, and if needed, an efficiently allocated share of the revenue gap. The difference or marginal cost revenue gap needs to be allocated to rate classes in the least distorting manner. Any class paying less than marginal cost plus the efficient allocation of the revenue gap is being subsidized by other customers, the utility's investors, or both. Cross-subsidies may also occur within a given class. To some extent these cross-subsidies can be ameliorated using the proper rate structure.

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

A. Rates need to be designed as a multi-part structure that preserves economically efficient price signals for the key components of the service. Costs that do not vary with on-going changes in usage should be recovered in fixed charges to keep volumetric (e.g., per-kW or per-kW) charges as close as possible to the underlying, near-term marginal costs.

Q. What are your recommendations for PSNH'S distribution rates?

A. PSNH's marginal costs associated with peak load growth are low on a system-wide average basis over the five-year planning period. The current per-kWh charges in PSNH's distribution rates generally exceed the per-kWh marginal costs of upstream distribution service, suggesting an artificially high incentive to conserve system-wide. Ideally, an efficient distribution rate would be a three-part rate that reflects the underlying structure of marginal costs of service. In particular, this rate would have the following rate components:

1. A monthly customer charge that recovers marginal customer-related costs (meter, service drop, customer-related expenses such as meter reading, billing, customer accounting, and customer information).

2. A monthly distribution facilities charge per customer's kW of design demand, that recovers the marginal costs of local distribution facilities; as discussed earlier this

concept of customer design demand is different from metered monthly customer maximum demand. Fluctuations of electricity usage by the customer from one month to the next do not free up transformer capacity available to serve him and other local connected customers on a long-term basis. Ideally, the billing systems would include a record of design demand or maximum average connected load for a given rate class. The charge can also be established as a per-contract kW charge for demand-metered customers, with the contract demand level set at no less than the highest 30-minute maximum demand recorded over the past 12 or 18 months.

3. Energy charges (ideally seasonally differentiated and differentiated by peak and off-peak) that recover the estimated marginal distribution substation and marginal trunk line feeder costs. This charge is applicable to incremental and decremental usage and it is critical to keep it as close as possible to marginal cost. It can be replaced by an on-peak demand charge for demand-metered customers.

The fixed charge may also be designed to include the marginal monthly distribution facilities costs (converted on a per-customer monthly charge using the average customer's design demand for the class), if a contract or facilities demand charge to recover those costs is not separately included in rates. This approach works better if the rate class includes relative homogeneous customers with comparable maximum non-coincident demands.

Recovery of other costs above marginal cost of service should ideally be included, to the extent feasible, in the fixed component of the rate. Generally, customer demand is less sensitive with respect to increases in the fixed component of the rates. Changes in the monthly bill from month to month are directly related to the specific volumetric charge. The caveat is that customer charges should not be increased to the point that it makes a customer disconnect from the grid, or relocate to other utility's service territory. Such an outcome would represent uneconomic bypass. Table 2 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 or contract demand. Marginal primary costs are also shown in two alternative ways – per kW of monthly metered demand and per kWh of usage. While these cost figures have not been marked up to reflect the class revenue targets, they are nevertheless useful to assess the efficiency of the price signals in the current rates.

Table 2: Marginal Unit Cost of Distribution Using Existing Distribution Rates

		Local Distribution Facility Marginal Costs		Time-Related Primary Distribution Marginal Cost		
Service Classification	**Customer Cost**	**Monthly Facilities Cost per Customer**	**Per-kW of Contract or Design kW**	**TOU Period**	**Per-kW of Max demand**	**Per-kWh**
	($/Cust./mo)	**($/Cust/mo)**	**($/kW-mo)**		**($/kW-mo)**	**($/kWh)**
R-P&L	14.91	16.96	1.46	All	0.46	0.00063
R-OTOD	17.15	16.96	1.46	Peak	0.46	0.00168
				Off-Peak	0.00	0.00001
R-C-WH	1.75	1.21	1.46	All	0.46	0.00063
R-UC-WH	1.75	1.21	1.46	All	0.46	0.00063
R-LCS	2.39	3.70	1.46	All	0.46	0.00063
GS-P&L-P1	15.04	27.22	1.39	All	0.46	0.00063
GS-P&L-P3	32.64	52.26	1.99	All	0.46	0.00063
GS-OTOD-P1	20.06	27.22	1.39	Peak	0.46	0.00168
				Off-Peak	0.00	0.00001
GS-OTOD-P3	44.33	52.26	1.99	Peak	0.46	0.00168
				Off-Peak	0.00	0.00001
GS-UC-WH	1.75	0.88	1.39	All	0.46	0.00063
GS-LCS-P1	2.39	n.a.	1.39	All	0.46	0.00063
GS-LCS-P3	7.41	n.a.	1.99	All	0.46	0.00063
GS-SH	4.52	5.66	1.39	All	0.46	0.00063
GV□	1,238.71	na	na	All	0.46	0.00063
LG	1,245.15	na	na	Peak	0.46	0.00059
				Off-Peak	0.00	0.00001

Q. What is your recommendation with regard to the residential fixed charges?

A. In the case of the Residential rate, the current fixed charge is below the marginal monthly customer costs. Because of this, too much of the class revenue target is being recovered through the kWh charge. There is currently a large difference between the existing volumetric charge and the underling marginal costs stated on a per-kWh. My recommendation was to lower the volumetric charge in existing standard residential rate R towards the estimated marginal unit costs, but limit increases in customer charges to avoid rate shock. A monthly facilities charge, converted to a per-customer charge for the average residential customer, would be about $17 per month. Together with the marginal residential customer-related costs of $14.91, this would mean a total fixed charge of $31.87, before considering the required increase of the Company's revenue requirement. PSNH is proposing a moderate increase of the customer charge to $13.89. This charge allows for 93 percent recovery of the marginal customer costs. A gradual plan to further increase small customers' fixed charges to the level of monthly marginal customers and facilities costs should be considered in the future to give more efficient signals about the true opportunity cost of keeping the customer connected to the system. Such process would require ensuring that low income customers receive appropriate bill rebates through a mechanism that tracks eligibility conditions.

Q. What is your recommendation for General Service rates?

A. My recommendation for rates GV and LG, is to increase their fixed charges towards a level closer to the marginal costs. In the General Service rate schedule, both the demand charge and kWh charges are too high as compared to marginal costs. The block charges are unnecessary because the price differential between block 2 and block 3 is too small to influence usage decisions. It would more appropriate to eliminate blocks or at least reduce them to have no more than two block charges. The size of the first block should be set so that the majority of customers in the class face the tail block price for at least a portion of their usage every month. The price of the tail kWh block would reflect the marginal cost, and recovery of sunk costs would take place in the first tier. In this economic environment of slow demand growth and sufficient grid capacity to meet most of the projected load forecast, declining block rates are helpful to bring the marginal prices closer to marginal costs of serving them. However, block rate structures with more than two tiers create confusion, since the customer does not know at which point in time within the month he has reached the next usage block level. Thus, block prices are not as effective to induce efficient usage behavior.

Q. What is the main benefit of lowering the volumetric charge?

A. With a lower kWh or metered kW charge that reflects the low cost that incremental usage imposes on PSNH's system, customers are not artificially constrained for using their electrical appliances or driven to use other forms of energy because of disproportionately high usage charges. They will have the opportunity to increase electricity use, while lowering their average cost of electricity and as a result, improve the efficiency with which society's resources are allocated. A change in usage in the off-peak period has no bearing on the station loading.

Q. What is your recommendation regarding the appropriate time of use periods for those rates that are time-differentiated?

A. The current Residential TOD rate is overestimating the peak marginal cost of service. A peak to off-peak differential of 13 cents per kWh, year round, is not cost reflective, even within the summer season. The broad peak period also leads no room for customers to save electricity costs in any substantial manner unless all usage is shifted to late night and weekends. The peak charge should be reduced and the off-peak charge may need to be increased to make sure that the absolute price differential between the peak and off-peak charges is closer to the underlying marginal costs price differentials. Developing efficient rates also requires to have seasonally-differentiated charges.

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

A. PSNH's proposed rate designs recognize that while a primary goal of rate design is to seek economic efficiency, consideration should be given to the need for gradualism. The Company is undertaking an increase in rates for all rate classes by increasing all rate components over the current rates. Instead of recovering the full revenue increase entirely on the volumetric charges of the rates, it has proposed a partial increase in the customer charges. This brings the fixed charge closer to the marginal customer cost for the residential class. Additional work is required towards efficient distribution rates that consider recovering not only marginal customer costs plus marginal facilities cost recovery on a more fixed basis, similar to what is already reflected in the optional time of day rates. This will allow decreasing the volumetric rates and more effectively signal the low prevailing incremental distribution cost of serve an additional kW. A stricter application of marginal cost principles to rate design would have resulted in even higher fixed charges for residential and general service customers. PSNH has not taken steps in the current rate case to improve the structure of the time of day rates by shortening the peak period. The introduction of seasonality in distribution rates is another aspect that is not being addressed at this time, but it is among the aspects of potential rate design that will merit consideration in later rate cases. Improved use of the system and reduced cross subsidies between classes are the main benefits to ratepayers that result from continuing to take into account marginal costs in rate design in the future.

Q. Does this conclude your testimony?

A. Yes, it does.