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

Allocated Cost of Service Study

On behalf of the Public Service Company of New Hampshire

d/b/a Eversource Energy

May 28, 2019

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Attachments

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I. INTRODUCTION

Q. Please state your name and current position.

A. My name is Amparo Nieto, and I am a Senior Vice President at Economists Incorporated ("EI").

Q. Please summarize your qualifications and experience.

A. I have over 20 years of experience providing advisory services and analyses on behalf of utilities, independent firms and energy regulatory commissions, in the context of energy regulatory policy design and wholesale electricity markets. I have advised extensively on the development of electricity marginal cost studies for use in the design of efficient rates and programs for utilities in California, Arizona, Maine, Minnesota, Oregon, New York, North Dakota, South Dakota and other states, as well as in provinces of Canada, such as in British Columbia, Manitoba and Newfoundland. I have reviewed and developed efficient utility electricity rate structures, recommended changes to utility demand response and interruptible rates, reviewed the impact of net metering rates on cost shifting among customers and designed improved compensation schemes for Distributed Energy Resources ("DER"). In New York, I was involved in the initial phase of the Reforming the Energy Vision (REV) docket, with regard to marginal distribution cost analysis for potential use in the Value of DER. I have also advised energy regulators and companies in Australia, Ireland, Spain, Africa and the Caribbean on electricity cost studies, regulatory policy, competitive markets, transmission cost allocation, distribution regulation and design of financial transmission rights. I contributed to the design and implementation of energy auction designs in Pennsylvania and Spain and advised the ISO-NE in various aspects of its wholesale capacity market rules. I am currently the director of the "Utility of the Future Rates Group," a working group sponsored by EI and open to energy utilities across North America. Additionally, I have conducted seminars on electricity marginal costing and rate design for rate managers and regulatory commission staff for over a decade. I have published energy papers and participated frequently as a panelist on industry and academic forums in the U.S. I hold a Master's degree in Economic Analysis and Public Finance from the Madrid Institute for Fiscal Studies in Madrid, Spain and a B.A. in Economics from the University of Carlos III of Madrid. My curriculum vitae is set forth in Attachment ACOSS-1.

Q. Have you testified previously before other regulatory bodies?

A. Yes. I have provided testimony before the Public Utilities Commission of Nevada, the New York Public Service Commission, the North Carolina Utilities Commission, the

Minnesota Public Utilities Commission, and the North Dakota Public Utilities Commission in the context of electricity marginal cost studies, electricity rate design and design of contracts with independent power producers. I have also provided expert testimony as part of the Salt River Project's price review process before its Board of Directors, with regard to SRP's proposal to reform their net metering rates. Overseas, I supported regulatory proceedings involving rate reforms in Ireland, Brazil, Kenya and Barbados.

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

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. The purpose of my testimony is to present the allocated cost of service study ("ACOSS") that I developed for PSNH for this rate case. In separate testimony, I also present the marginal cost of service study ("MCOSS") I prepared for PSNH, which represents an update to the MCOS study I developed in the context of the New Hampshire Net Metering proceeding (Docket No. DE 16-576). These studies provide information useful for class revenue requirements and rate design and I advised PSNH on the best manner to apply these results. The ACOSS is provided as Attachment ACOSS-2 (Pro Forma Cost of Service Study) and Attachment ACOSS-3 (Per Books Cost of Service Study).

Q. How is your testimony organized?

A. My testimony is organized as follows.

- In Section II, I summarize my testimony.
- In Section III, I discuss the methods to estimate the various components of the allocated cost of service study.
- In Section IV, I describe the resulting revenue targets by rate class and how they compare with revenues for the test year.
- In Section V, I discuss the main conclusions.

II. SUMMARY OF TESTIMONY

Q. Please summarize your direct testimony on the allocated cost of service study.

A. PSNH's ACOSS is intended to identify the relative responsibility of each rate classification for the recovery of the overall costs of distribution service in the test year, 2018. The ACOSS determines the overall rate of return overall and by rate class and the degree of over/under recovery of allocated costs under existing tariffs. Thus, it indicates the changes to present rates that would be necessary to result in equal rates of return on rate base for each class. Any rate class paying less than this cost allocation is assumed to be cross-subsidized by other classes based pm the ACOSS approach. In practice, the Company is expected to use the ACOSS results as a guide, but in a manner that recognizes customer impact considerations.

The 2019 study begins with the review of the Company's proposed distribution revenue requirement (operating expenses, net plant, taxes, depreciation, etc.) for the test year ending December 31, 2018. Two versions were computed, an adjusted "per books" test year, and a proforma test year.

The ACOSS develops cost allocation factors for the different components of plant and expenses using each rate class' share of various measures of demand, from load research provided by the Company, and test-year customer numbers, as well as from weighting factors as applicable to meter costs, and customer-related expenses. Under the ACOSS method, customers are assumed to be responsible for a share of the sunk, historical demand-related costs in proportion to kW of coincident and non-coincident demand by class, customer numbers, weighted expenses by class and other cost drivers. A discussion of these results is provided in Section IV of my testimony.

III. METHODS USED IN PSNH'S ACOSS

Q. How are the various distribution plant costs classified in the ACOSS?

A. The study distinguishes between demand-related and customer-related costs. Distribution station plant (account 362) is considered in its entirety as demand-related. Transformers, including step transformers and service transformers (Account 368), as well as the underground and overhead circuits (Accounts 365, 366, and 367), are considered to have both a demand and a customer-related component. The split of these accounts is based on the results of the Company's Minimum System ("MS") Study. Meters, service drops and installations on customer premises, are considered to be entirely customer-related, and allocated on the basis of both relative differences in installed costs and customer numbers.

Q. Would you please describe the minimum system study and the resulting classification factors?

A. The MS study involves the following steps (also described on pages 90-92 of the NARUC manual):

- Step 1: Determine the minimum sized conductor, transformer and service is installed on the distribution system.
- Step 2: Determine the installed cost per unit for the minimum sized plant. Installed costs include material costs, labor costs and equipment costs.
- Step 3: Multiply the cost per unit of the minimum sized plant by the total inventory of each plant type.
- Step 4: The total cost of the minimum sized plant is divided by the total cost of the actual sized distribution plant in the field. This ratio is deemed to be the customer-related portion of distribution plant investment, with the balance being the capacity-related portion.

Table 1 below indicates the percent of distribution plant classified as customer and demand-related as per the results of the MS method.

Table 1. Minimum System Study Classification Factors

Account	Demand	Customer
364 POLES - PRIMARY	23.5%	76.5%
364 POLES - SECONDARY	16.9%	83.1%
365 PRIMARY OH LINES	59.2%	40.8%
365 SECONDARY OH LINES	66.1%	33.9%
366 PRIMARY UG LINES 1-PH	82.3%	17.7%
366 PRIMARY UG LINES 3-PH	92.8%	7.2%
366 SECONDARY UG LINES	58.4%	41.6%
367 PRIMARY UG LINES 1-PH	82.3%	17.7%
367 PRIMARY UG LINES 3-PH	92.8%	7.2%
366 SECONDARY UG LINES	58.4%	41.6%
368 OH TRANSFORMERS	17.6%	82.4%
368 UG TRANSFORMERS	78.9%	21.1%

Q. How do you allocate the demand-related costs of transformers and conductors?

A. Distribution facilities, from a design and operational perspective, are installed primarily to meet localized area loads, and so customer-class non-coincident peak demands ("NCP"), or even individual customer maximum demands are suitable to allocate the demand component of distribution facilities. PSNH's ACOSS uses class NCP to reflect the ratio of the class's maximum demand in the year compared to the sum of all the classes' highest annual demands, irrespective of when those demands occur. Class NCP allocators take into account the diversification of loads at the rate class level.

Q. Have you made any changes with regard to the allocation method for other demand-related costs as compared to the Company's allocated cost study filed in the 2009 rate case?

A. Yes. I have made several changes with regard to station accounts 360-362. The 2019 ACOSS distinguishes between the elements of distribution plant that are installed to meet loads during the highest system peak hours in the year, such as the case of bulk distribution substations, and investments that are driven by less diversified demands, such as conductors and transformers. The 2019 study employs a combined or hybrid allocator for the allocation of distribution substation plant account that takes into account both the class contribution to the top 20 distribution system coincident peak hours in the test year, and class NCP demands. This is a departure from the method employed by PSNH in previous studies, which relied entirely on class NCP for all demand-related distribution plant. NCP-based allocators are less likely to reflect cost causation with regard to distribution substations, which must have sufficient capacity to meet the distribution station coincident peak demands, not the sum of non-coincident demands by rate class. Thus, a hybrid allocator for this element of plant does a better job at reflecting cost causation than just relying on class NCP.

Q. How did you determine the hybrid class allocator for station plant?

A. The first step was to determine what portion of the substation plant account represents bulk stations versus lower voltage distribution substations. Although both types of distribution substations may peak at the time of (or close to) the system coincident peak, the bulk stations are more likely to do so, according to my review of hourly loads at individual bulk stations. Hourly load data at the lower voltage substation was not available to be able to determine their coincidence factors. A pure 20CP allocator would have not assigned any cost responsibility to classes that only contribute to the winter peak. A very small percentage of PSNH's stations peak in the winter. A class NCP allocation approach is useful to recognize that not all elements of the distribution system experience their peak load at a time coincident with the system peak and give a greater cost responsibility to rate classes that peak outside that peak. I determined that 53 percent of account 362 (and associated operation and maintenance expenses) should be allocated to customer classes on the basis of their contribution to the average of the 20 hours of maximum system demand (20CP) and 47 percent on the basis of class NCP. This split was based on the relative total replacement costs of bulk stations vs. non-bulk substations.

Q. Why did the study rely on 20 peak hours as opposed to single peak?

A. In order to recognize that there is more than one coincident peak hour that the utility would consider for planning purposes, the allocator uses the highest 20 coincident station peak hours as opposed to a single coincident peak hour. This is also consistent with assuming five days of critical peak demands in the summer, with four critical hours on average in each day. A review of the system distribution retail and wholesale hourly loads the test year (excluding the loads of transmission customers) revealed that 2018 had high peak loads within 95 percent of the highest summer peak load for four days in August and one day in July, and at least three sequential hours of sustained peaks in those days. These hours were used to identify the top 20 hours.

Q. Does the new method to allocate station plant have a major impact on the allocated costs as compared to class NCP?

A. I compared the new system-coincident method for station plant with the older NCP approach. There are differences of less than 1 percent for the Residential and General Service rates. The classes that are less coincident with system peak, such as water heater rates for both residential and general service customers, general service space heating rate, and street lighting rates OL and EOL receive a lower allocation of station plant as compared to a pure NCP method. The new result is, however, more aligned with cost causation for these rates than the method employed in the past. For example, in the case of street lighting, their usage does not impact the high voltage distribution system, because they are only turned after the peak hours in the summer season. This means that the distribution planners do not need to take streetlight usage into account when deciding how much capacity is needed at a given substation. The only exceptions are those streetlights located in areas served by substations that peak in the winter months. At the moment, those substations only represent approximately 10 percent of the entire system load in PSNH's system.

Q. What changes have you introduced in the context of allocating costs of distribution plant, other than station?

A. The prior study adopted the results of the MS Study combining single-phase and multi-phase equipment. Customers who do not receive service off the single-phase primary distribution system should not pay the costs of this part of the distribution system. Thus, the 2019 ACOSS uses separate classification factors for single phase versus three-phase wherever separate accounting cost information is available, to avoid allocating costs to three-phase customers of equipment that they do not use. I relied on the split on miles of single-phase and multi-phase distribution plant and their associated replacement cost (in dollars per mile) to establish a separation of accounts within primary lines (accounts 366 and 367). I also created distribution line cost allocators to account for the differing usage of the single-phase portions of the system by different customer classes, based on the information provided by the Company regarding the number of 3-phase customers within the General Service Rate. All GV and LG customers are three-phase customers. This separation was only possible for accounts 366 and 367, since the inventory in other accounts was not detailed enough to identify the phase of the conductor.

Q. How did the ACOSS account for the fact that large commercial customers own their own transformers?

A. The allocation of demand-related costs in Account 368 uses an adjusted class NCP allocation factor to exclude the share of NCP associated with customers in GV and LG rates who are served from customer-owned transformers. All other customers in classes GV and LG rent a transformer from the company. This adjustment relied on a review of transformer ratings owned by these customers, compared to the rating of the total transformers dedicated to the class (customer-owned plus rented transformer). The share of customer-owned transformer ratings was assumed to represent the share of the class NCP associated with the customer-owned transformers. The revenue from rental of transformers (account 454) is applied to the classes GV and LG as corresponds based on the test-year rental payments by these classes.

Q. Do you see any limitations in the allocation factors for distribution plant and expenses?

A. There are limitations in the precision of the ACOSS allocators, but these are inherent to any allocated cost study that relies on limited granularity in accounting cost records. For example, the transformer plant, in account 368, does not distinguish between the primary step transformers, which convert power voltage down to a lower level but do not directly connect customers' premises to the grid, and the service line or secondary transformers, which directly connect customer premises to the grid. The former are built based on more diversified demands and could arguably be allocated on the basis of the hybrid approach, just like the lower voltage distribution costs. The service transformers need to attend to the more local demands of the customers connected to them. Likewise, given the limitations of accounting data, there was not enough detail to isolate the costs of trunk-line, upstream primary feeders from the rest of plant in accounts 365-367. Upstream feeders are driven by coincident peak demands at the substation. The study allocates all demand-related costs of accounts 365-367 and all demand-related costs of account 368 on the basis of class NCP. Lastly, another limitation has to do with the customers served at the 34.5 kV voltage level. These customers should not need to pay for the cost of lower voltage systems, but the accounting records do not distinguish by voltage level other than primary and secondary. Again, this is a common limitation in ACOSS allocation methods when only aggregated plant account records are available.

Q. How does the ACOSS allocate customer-related plant and expenses to customer classes?

A. Customer-related costs vary with the number and type of customers. When customers are added, the Company faces higher costs for customer service expenses such as meter reading, collection and inspection, billing, and bad debts. New meter and service drops are also installed. Relative weights were estimated to reflect differences in the effort required and the cost incurred to provide customer services to individual customers in each rate class. Examples of customer allocators are as follows:

- Meter reading allocation factors were based on number of meter reads and average cost per read, by class, as provided by the Company;
- Allocation factors for the meter plant were based on the relative ratios of the average installed meter cost within a class; with the relative weight of a residential customer set equal to one, each of the other classes is assigned weighting factors. The ratios of the weighted customer counts for each class to the total weighted number of customers provides the customer allocation factor.
- Collection expenses were allocated to residential and general service based on the number of customers in these categories and average per-customer cost by class.
- Bad debts and other customer accounts expenses were allocated on the basis of the review of accounts by the Company on the relative amount of these expenses by class.

- Customer service and informational expenses (accounts 908 and 910) were assigned to rates GV and LG only.

The specific costs associated with streetlights (such as luminaires, ballasts, light bulbs and other equipment necessary for street lighting, including an allocated share of general plant) were allocated directly to the streetlight class OL. These are accounts 371 and 373.

Q. How does the ACOSS treat load control service customers?

A. These customers do not have separate treatment in the ACOSS because the Company does not have the curtailment rights for distribution reliability reasons. Therefore, the peak demand of these customers is considered in full when determining the demand-related cost allocations.

Q. How does the ACOSS treat the customers of standby Rate B?

A. Standby rate customers should not be treated differently in the ACOSS because in theory they should pay the same as full requirements customers in the otherwise applicable rate, as long as they impose the same costs on the system. The ACOSS uses the same allocator type as the rest of the classes, i.e., the 20CP/NCP allocator station plant and class NCP for other demand-related costs. This are based on records of actual non-coincident back-up demands of the customers GV-B and LG-B.

Q. How does the ACOSS treat streetlighting rates?

A. The study assigns costs to streetlighting using an equivalent customer-method that assumes that street light fixtures will require a share of the transformer in proportion to its monthly usage, i.e., a fixture would require a specific kW of transformer capacity equal to 10 percent of the capacity required by a residential customer assuming that the fixture monthly usage is 10 percent of the average residential customer. While this is imprecise, it is a second-best solution given the lack of information as to how many fixtures are connected to the same transformer on an average, system-wide basis in the service territory.

IV. RESULTS OF REVENUE TARGETS BY CLASS

Q. What does the ACOSS determine in terms of the adequacy of current distribution rate levels?

A. The results of the 2019 ACOSS demonstrate that PSNH's existing distribution rates are inadequate to allow the Company to recover the test year cost of providing electric distribution service in New Hampshire with a reasonable rate of return on its electric property used and useful. PSNH is currently requesting an overall revenue requirement increase for distribution rates of approximately 20 percent, which would provide an overall return on rate base of 7.62 percent in the proforma test year version. The overall earned rate of return that the Company currently obtains from current rates is 3.45 percent, which is less than half of the target return. With regard to the realized return on rate base by class, the ACOSS proforma results show very divergent class rates of return at current rates. Other that General Service customers and Large General Service customers, all other classes are either paying significantly less or significantly more than their proportional share of allocated costs. Figure 1 below illustrates the earned returns by rate class. Both residential LCS and general service LCS test-year revenues provide a negative return on allocated rate base. The combined Residential & Residential TOD provide almost no return, as well as the residential Water Heating rate. By contrast, all other commercial, industrial, and streetlighting classes currently provide above average returns.

<u>Figure 1. Realized Rate of Return by Rate Class at Current Revenues</u>

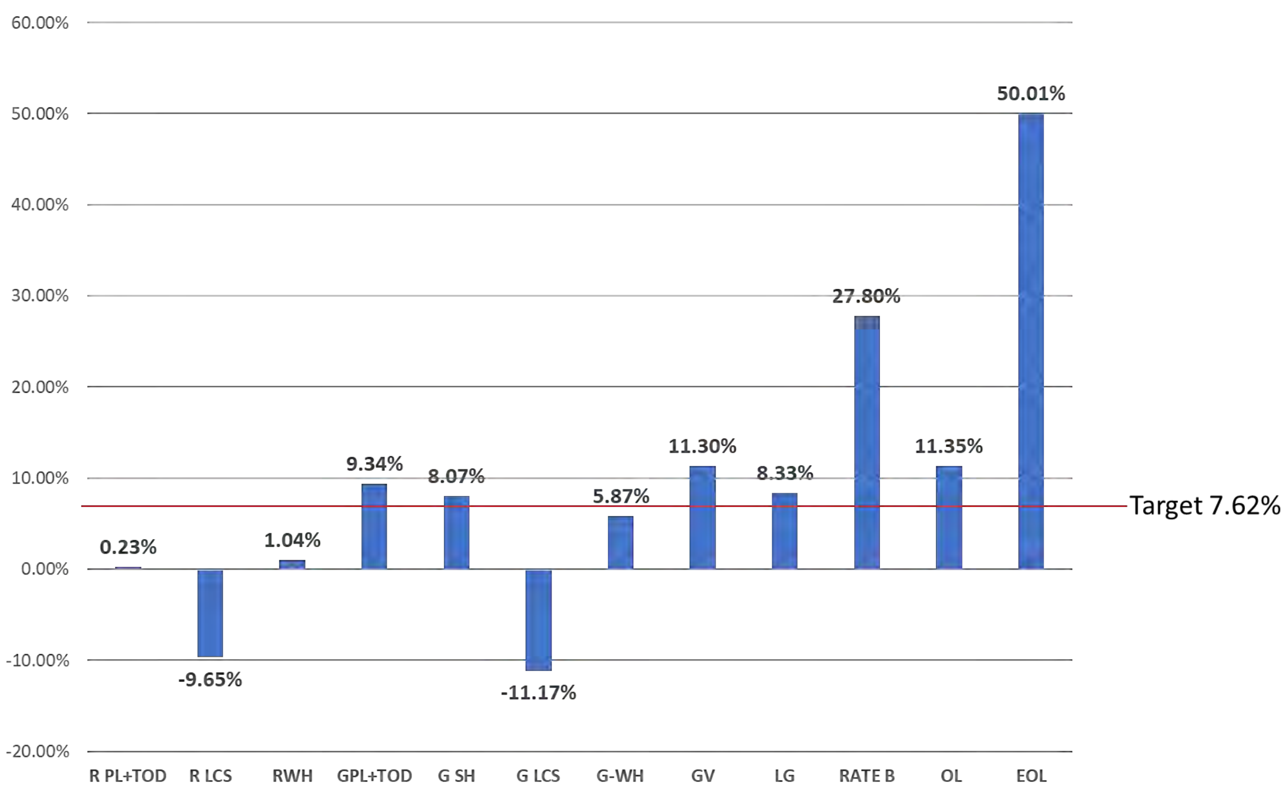

Table 2 below provides a summary of the pro forma test year ACOSS target revenue requirement results at the class level. Table 3 provides the same information for the "Per book" test year. The detailed 2019 ACOSS output is included in Attachment ACOSS-2.

As shown in the proforma test year, the rate classes that would need to experience a significantly larger than average percent increase to achieve the Company target rate of return of 7.62 percent are the residential rates RPL+TOD, residential and general service

LCS, residential water heating, and General service LCS. The residential customers are paying about 29 percent less than their proforma revenue target. This class makes up about 66 percent of the overall rate base. Thus, bringing all rate classes to parity after netting out other revenues would require a significant percent increase for the standard residential rate (about 41.2%). This is generally consistent with the results of the MCOSS for the Residential class. The General Service rate (combined G P&L and G TOD) customers are contributing by more than the average required return and would see a decrease of about 6.5 percent. Rates GV and LG would also be reduced by 14 percent and 3 percent, respectively. In the case of street lighting, both rates OL and EOL appear to be over-recovering and would need to be reduced by about 10 percent and 51 percent, respectively.

Table 2: Distribution Revenue Requirement and Required Rate Change
Proforma for Test Year 2018

Description	Test Year 12/31/2018 Proforma	R PL+TOD	R LCS	RWH	GPL+TOD	G SH	G LCS	G-WH	GV	LG	RATE B	OL	EOL
Rate base	1,215,668	796,079	4,228	15,186	226,652	576	380	392	100,105	57,956	2,458	8,965	2,690
Operating income	41,945	1,804	(408)	158	21,180	47	(42)	23	11,309	4,829	683	1,017	1,345
Earned rate of return	3.45%	0.2%	-9.7%	1.0%	9.3%	8.1%	-11.2%	5.9%	11.3%	8.3%	27.8%	11.3%	50.0%
Requested rate of return/cost of capital	7.62%	7.62%	7.62%	7.62%	7.62%	7.62%	7.62%	7.62%	7.62%	7.62%	7.62%	7.62%	7.62%
Required operating income	92,590	60,633	322	1,157	17,263	44	29	30	7,624	4,414	187	683	205
Revenue increase/(decrease)	**69,913**	**81,209**	**1,008**	**1,378**	**(5,408)**	**(4)**	**99**	**9**	**(5,086)**	**(572)**	**(685)**	**(462)**	**(1,574)**
Distribution Revenue Requirement	$ 436,203	$ 288,050	$ 1,476	$ 5,628	$ 80,338	$ 201	$ 129	$ 148	$ 34,447	$ 19,376	$ 831	$ 4,062	$ 1,518
Other Revenue	16,428	$ 9,810	$ 22	$ 62	$ 1,945	$ 3	$ 2	$ 2	$ 3,384	$ 1,134	$ 27	$ 22	$ 16
Net Distribution Revenue Requirement	**419,775**	**$ 278,239**	**$ 1,455**	**$ 5,567**	**$ 78,393**	**$ 198**	**$ 127**	**$ 146**	**$ 31,063**	**$ 18,242**	**$ 804**	**$ 4,040**	**$ 1,502**
Current Distribution Revenues	349,862	$ 197,030	$ 447	$ 4,188	$ 83,801	$ 201	$ 29	$ 137	$ 36,149	$ 18,814	$ 1,489	$ 4,501	$ 3,077
Required Change in Rates	**19.98%**	41.22%	225.63%	32.91%	-6.45%	-1.79%	341.80%	6.91%	-14.070%	-3.042%	-46.01%	-10.25%	-51.18%

**Table 3: Distribution Revenue Requirement and Required Rate Change by Rate Class
Adjusted Per Book, Test Year 2018**

Description	Test Year 12/31/2018 Per Book	R PL+TOD	R LCS	RWH	GPL+TOD	G SH	G LCS	G-WH	GV	LG	RATE B	OL	EOL
Rate base	1,219,367	798,527	4,241	15,226	227,341	578	381	393	100,411	58,139	2,466	8,977	2,686
Operating income	53,752	9,987	(369)	320	23,284	51	(39)	27	12,012	5,189	696	1,195	1,398
Earned rate of return	4.41%	1.3%	-8.7%	2.1%	10.2%	8.9%	-10.3%	7.0%	12.0%	8.9%	28.2%	13.3%	52.1%
Requested rate of return/cost of capital	7.08%	7.08%	7.08%	7.08%	7.08%	7.08%	7.08%	7.08%	7.08%	7.08%	7.08%	7.08%	7.08%
Required operating income	86,346	56,545	300	1,078	16,098	41	27	28	7,110	4,117	175	636	190
Revenue increase/(decrease)	**45,092**	**64,410**	**926**	**1,049**	**(9,941)**	**(14)**	**92**	**1**	**(6,781)**	**(1,483)**	**(721)**	**(774)**	**(1,671)**
Distribution Revenue Requirement	$ 410,714	$ 270,667	$ 1,394	$ 5,299	$ 75,727	$ 190	$ 123	$ 139	$ 32,748	$ 18,464	$ 795	$ 3,749	$ 1,421
Other Revenue	15,760	$ 9,227	$ 21	$ 62	$ 1,867	$ 3	$ 2	$ 2	$ 3,380	$ 1,134	$ 27	$ 22	$ 15
Net Distribution Revenue Requirement	**394,954**	**$ 261,440**	**$ 1,373**	**$ 5,237**	**$ 73,860**	**$ 187**	**$ 120**	**$ 137**	**$ 29,368**	**$ 17,331**	**$ 768**	**$ 3,727**	**$ 1,405**
Current Distribution Revenues	349,862	$ 197,030	$ 447	$ 4,188	$ 83,801	$ 201	$ 29	$ 137	$ 36,149	$ 18,814	$ 1,489	$ 4,501	$ 3,077
Required Change in Rates	**12.89%**	32.69%	207.35%	25.05%	-11.86%	-7.19%	318.13%	0.39%	-18.759%	-7.884%	-48.42%	-17.20%	-54.32%

V. CONCLUSION ON ACOSS AND USE OF RESULTS

Q. Is the ACOSS a good reference to set efficient price signals?

A. An allocated cost of service study does not serve economic efficiency goals such as optimizing the use of the system. It is not a reasonable basis to determine which costs should be recovered in the per-kWh charge versus the fixed charge. Allocated cost studies are commonly relied upon as a guide to set revenue targets but are rarely used to inform the levels of specific rate components. One of the key differences between the ACOSS and MCOSS is the share of costs that each study considers to be customer-related versus demand-related. In the ACOSS for the test year, residential customer-related costs represent about 63 percent of the residential revenue requirement, with 26 percent considered to be related to non-coincident demand and 26 percent related to coincident peak demand. This would translate to a customer charge of $31.24, assuming that the rate is increased to provide the average required rate of return. The ACOSS is more likely to be used to justify higher demand or kWh charges as compared to a marginal cost-based rate design method. Even if the ACOSS method used similar allocators as the MCOSS, a lower than optimal proportion of costs would get classified as customer or fixed kW-related costs particularly in the current context of slow demand growth and lower need for peak-load related investments. For a broader discussion of rate designs that meet efficiency and equity rate objectives, please refer to my direct testimony on marginal costs.

Q. What is your overall conclusion about the ACOSS results?

A. I have developed an allocated cost of service study that relies on best practice methods, subject to the limitations in the granularity of the accounting costs and keeping in mind the need for gradualism. The study demonstrates that rates are currently out of line with best practice ACOSS methods and need to be realigned, taking into account avoidance of rate shock, after considering the weight of the distribution rate in the overall customer bill.

Q. Does this conclude your testimony?

A. Yes.