Summary of Material Changes in MCOSS as filed for PSNH's Rate Case in Docket No. DE 19-057 on May 28, 2019 with regard to the July 2018 MCOSS under Docket No. DE 16-576

The 2019 marginal cost of distribution service study ("MCOSS") incorporates a number of changes with regard to the MCOSS filed in July 2018. All material changes took place with regard to the calculation of marginal distribution bulk and non-bulk costs.

1. The planning period used in the MCOSS has been modified to include years 2020 through 2024 (as opposed to years 2019-2023 as in the July 2018 study).

2. The 2019 MCOSS uses an updated Capital Expansion plan. Certain distribution projects have either been delayed or modified by the Company and the updated MCOSS reflects these changes. The 2019 MCOSS also includes the cost information of two new bulk station capacity related projects that are now identified as capacity-related in the capital plan.

3. The 2019 MCOSS further identifies and separates for certain projects the cost associated with station capacity expansion to meet peak load from other project costs that are purely driven by the need to modernize the station or to improve its condition. As part of this refinement, a large transformer replacement investment amount (over $40 million) that was in the Company's Capital Plan has now been excluded from the MCOSS. This forecast was previously assumed to include mostly peak-load related station replacements. EI learnt upon further discussions with the Company that this forecasted investment will involve a large number of "asset condition" station projects.

4. The 2019 MCOSS identifies the bulk stations that will fail to meet the N-1 contingency standard during the 2020-2024 timeframe, or the number of transformer investments that would be needed in order to meet the 75% design criteria over the same period. The Company has indicated that it does not expect to be able to address all of the investments required to meet N-1 at the bulk level during the next five years. To be consistent with the Company's planning practice and the latest Capital Plan, the 2019 MCOSS substation investment marginal cost only reflects the N-1 projects that are effectively planned and more likely to be undertaken by 2024. The various adjustments result in a lower share of the system expected to include capacity-expansion areas (from 34 percent as estimated in the earlier MCOSS to 20 percent). As a result of these changes the 2019 MCOSS produces a lower system-wide average investment for the period 2020-2024.

5. The 2019 MCOSS uses different planning criteria for non-bulk distribution investments

which has resulted in a lower amount of non-bulk station investment for the period 2020-2024 as compared to the July 2018 study. The 2018 MCOSS used transformer normal nameplate rating to identify when the station was due for expansion. Additional discussions with the Company identified that in the case of non-bulk stations, the prevailing planning practice is not to expand the station until the peak load reaches its LTE (Long Term Emergency) rating. The Company has also confirmed that for the particular stations that had been identified as constrained, the Company will be able to switch load off to a nearby substation. This practice is considered prudent under current reliability standards and reduces costs to consumers.

6. The probability of peak analysis has been updated to include hourly bulk station loads of year 2018. This update allocates more probability of distribution peak to hour ending 12 as compared to the July MCOSS and a lower probability of peak to hour ending 8 pm.

Marginal Cost of Distribution Service Study and Implications for Rate Design

Prepared for the Public Service Company of New Hampshire

d/b/a Eversource Energy

May 28, 2019

Economists
INCORPORATED

Project Director

Amparo Nieto

Senior Vice President

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Eversource Energy's Marginal Cost of Distribution Service Study and Implications for Rate Design

I. INTRODUCTION

Eversource Energy ("Eversource", or "The Company"), retained Economists Incorporated (EI) to develop a system-wide marginal cost of service (MCOS) study for electricity distribution service in New Hampshire for a five-year planning period 2020-2024. EI has developed a forward-looking MCOS study that takes into account the Company's prevailing engineering design standards and planning process. In the context of the utility distribution service the marginal cost requires evaluating the utility's response, from a planning perspective, with respect to either a small anticipated change in the use of the system in a given hour, or changes in customer connections or service requirements.[1]

This report summarizes the approach that EI has followed to estimate upstream distribution marginal costs by voltage level of service, local distribution facilities costs, and marginal customer costs, and presents a summary of the results.

The results of the MCOS study are helpful to inform the direction of reforms that are needed for Eversource's distribution rate designs, in terms of both structure and rate levels of rate components Additionally, it provides useful information on the time-differentiated distribution value of load reductions from customer-sited distributed generation (DG), as well as other distributed energy resources (DERs).

[1] Marginal cost also represents the value of those resources in their next best alternative use, known as the opportunity cost.

II. UPSTREAM DISTRIBUTION MARGINAL COSTS

A. Elements of Primary System

The NH system is varied and complex. The starting point for the MCOS study was identifying the various elements and voltage levels of the Company's distribution system. Eversource's primary voltage distribution system includes the following main elements:

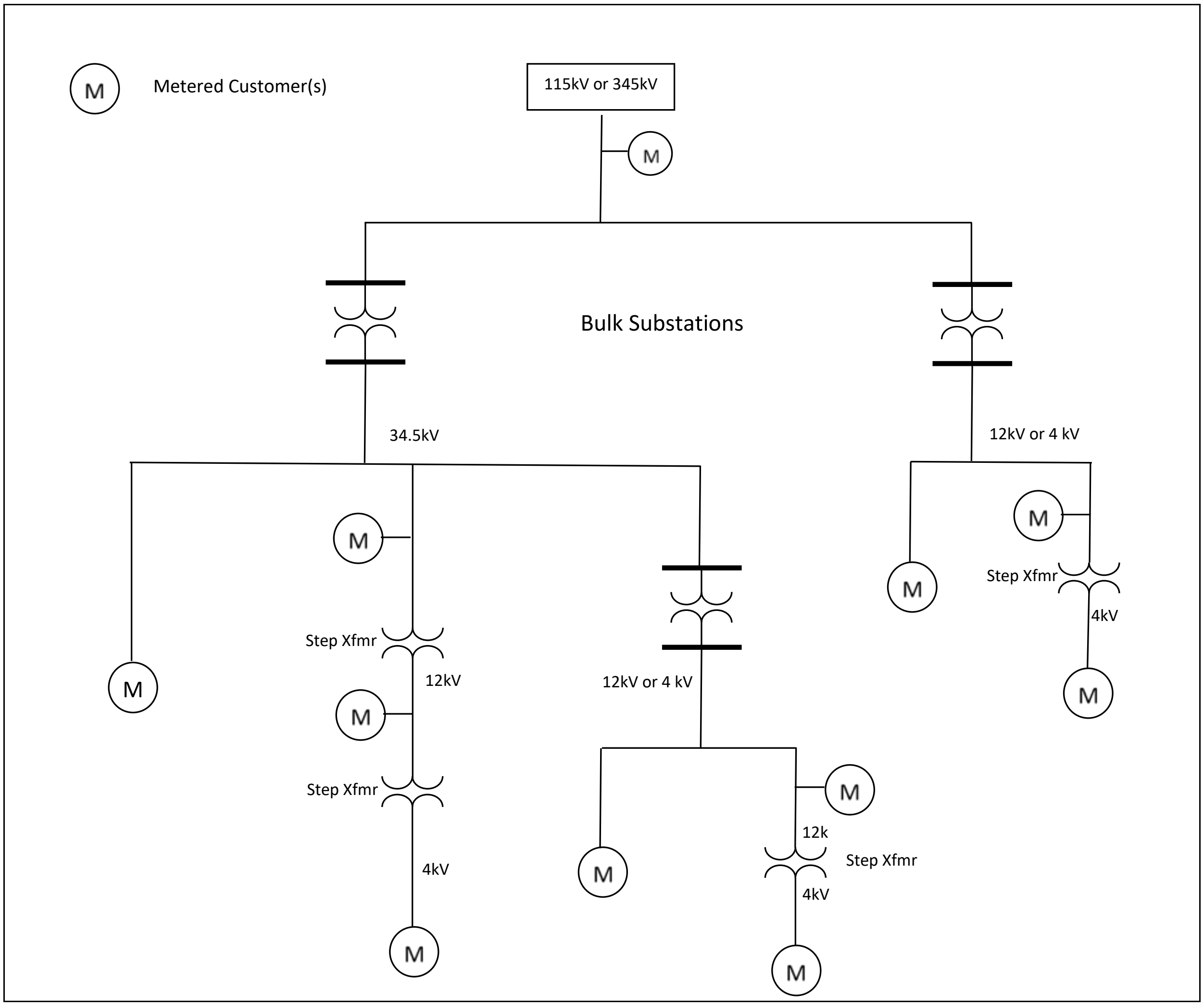
- Bulk stations that are fed from the transmission system (115kV) and typically convert power to 34 kV or directly to 12 kV;
- Distribution (non-bulk) substations that convert the load coming from the bulk station to either 12 kV or 4 kV, and
- Trunk-line primary feeders.

The Company's has an extensive 34.5kV system. About 340,000 customers (about 83 percent of the total load) are connected to this system through small pole mounted step transformers that convert the load coming from the bulk system to either 12.47 kV or 4.16 kV.

The remaining 17% of the load is served from distribution substations. A small share of Eversource's service territory customers (about 30 MW) receive electricity from bulk stations that are located in Vermont. At the more local level, Eversource's distribution facilities include local primary taps, primary-to-secondary transformers, switchgear, secondary lines, and service drop.

Eversource also serves wholesale distribution customer loads from its system. These loads need to be taken into account when designing the system, just as the retail loads, and are therefore considered when estimating the share of stations that are likely to require capacity expansion to meet peak load growth. The simplified diagram below illustrates the variety of configuration of Eversource's distribution system.

Figure 1. Typical Eversource New Hampshire's Electricity Distribution System



B. Marginal Substation Investment

The MCOS builds upon an in-depth review of the Company's budgeted investments for the upcoming planning period (2020-2024). Eversource, like many other distribution utilities, generally predicts the required investments in non-bulk substations to meet expected peak load with sufficient confidence within a timeframe of two to three years. Projected distribution capital expansion investments further into the future are less certain and subject to further review based on monitoring growth of station peak loads as the date approaches. The 2019 MCOS utilizes project expectations as per the Company's capital plan over years 2020-2024, along with information on expected peak load conditions over the study period to compute marginal station costs. This is necessary to provide a longer-term view of marginal costs.

EI reviewed the current and expected station peak loading as well as existing transformer nameplate ratings over the next five years. Our review identified specific bulk station and distribution substation expansion projects that are needed to address N-0 and N-1 limitations in meeting peak load reliably based on the current standards. These projects generally involve replacement of existing substation transformers with one (or two) larger transformers. The investments intend to address existing or expected overload conditions, serve new step industrial or commercial load additions, and/or offload nearby substations. A number of stations not currently in the Company's capital plan are at or moderately exceeding the maximum peak loading allowed under N-1 criteria. However, upon consultation with the Company, a decision was made not to include these stations in the MCOSS since the Company does not expect to address those N-1 related capacity needs in the current five-year horizon.

EI isolated the cost associated with capacity expansion to meet peak load from other costs that are purely due to modernize the station or improve the condition of the transformer and would need to be incurred regardless of changes in peak load. In general, the MCOS excludes investments that are incurred to address a change in the substation configuration, including such items as replacement of electromechanical relays with numerical relays, or other reliability-related costs that are unique to the stations and not triggered by growth in load (or avoided by load reductions). Projects associated with retirement of obsolete equipment were entirely left out of the MCOS calculation, since these are one-time investments and are unlikely to be impacted by growth or reductions in load.

Going forward, the Company does not foresee significant peak load growth on a system-wide basis. Eversource's peak loads in the New Hampshire system are expected to grow generally at less than 1 percent per year throughout the study period, albeit growth is not uniform across the system. The Eastern and Central and regions are expected to experience relative larger than average demand growth due to higher commercial and industrial activity in a number of areas. The majority of the bulk stations and substations are expected to be able to accommodate load growth without needing a capacity addition over the upcoming five-year period.

To compute the marginal cost of bulk and distribution stations we divided the identified peak-load related station investments by the station's project added capacity. In the case of bulk stations, converting the marginal investment per kW of added capacity to a dollar per-kW of added peak load carrying capability required using the N-1 design criteria o adjustment factor. N-1 criteria in the case of bulk stations requires that the station is pre-loaded at no more than 75 percent of its normal (nameplate) rating, to avoid compromising the station long term emergency rating.[2] On the other hand, non-bulk substations are not generally considered for an upgrade until their loads begin to reach their long term emergency (LTE) rating. Thus, no adjustment factor was necessary in the case of marginal non-bulk substation costs.

C. Operation and Maintenance Expenses

Marginal distribution station and line O&M expenses are a component of marginal distribution cost, since these expenses increase as the amount of plant in service does. EI reviewed the Company's FERC Form 1 annual distribution O&M expenses in recent years (2014-2018) and divided the annual expenses by the kW of non-coincident peak demand at bulk stations and distribution substations, separately for each type. Upon review of the annual expense per kW (in constant dollars) in these years, the average of the per-kW expenses over the four-year period was used to represent expected marginal O&M expenses per kW of station peak load.

D. System-wide versus Locational Cost Estimates

Eversource's standard distribution rates do not vary by geographical location, therefore, EI calculated a system-wide marginal cost by multiplying the locational cost by the peak-load share of the bulk and distribution stations that are expected to require peak-load related capacity investments over the five-year period, as compared to total retail load. Because of the higher uncertainty of station peak load growth beyond a two-year timeframe, a number of non-bulk distribution capacity expansion investments are not formalized or specifically identified by area in the plan. The MCOS study uses available information of regional forecasts of annual peak load growth, along with information on known industrial step load additions at specific stations to estimate the share of the system potentially subject to requiring growth-related expansion over the full five-year period as new load materializes. A review of the station loads and nameplate ratings revealed that most areas, including some of the high-growth regions will have ample station capacity to serve peak loads during the study period. A zero marginal cost is implicitly assumed for these areas.

Finally, the marginal non-bulk substation cost was adjusted to recognize that they only serve about 17 percent of total retail load. The marginal bulk station cost was adjusted to take into account that about 2 percent of the retail load is not served from stations located in Vermont.

The bulk station and distribution substation marginal costs were annualized, both for the capacity-expansion areas and as a system-wide average marginal cost estimate, using marginal

[2] The emergency rating reflects the load that can be sustained for a limited number of hours before voltage instability (or ultimately loss of load) occurs.

O&M expenses, and loading factors.

E. Time-differentiation

The annualized marginal bulk station and marginal distribution costs must be allocated to those peak hours in the year when load growth (or load reduction) is more likely to have an impact on the planned investment decisions. The MCOS uses hourly probability of peak factors for each typical weekday and weekend by month to allocate the annual marginal bulk station and non-bulk substation costs to hours and months. An analysis of the combined hourly load shapes of the entire set of Eversource's bulk substations during the four most recent four years (2015 through 2018) to account for weather variability showed that load growth that peak hours of weekdays in July and August drive distribution capacity expansion. Only a small number of bulk substations, representing about 10 percent of the total load, peak outside of the summer season, in the winter months of December or January. The months of July and August account for 97 percent of the system-wide annual probability of distribution peak. The remaining 3 percent falls in the months of September and June.

The seasonality observed in the resulting hourly marginal costs indicates that consideration of seasonality for Eversource's distribution rates may be required for efficient pricing. These results also show that the broad definition of the peak period in current rates (7 am to 8 pm, Monday through Friday) is not appropriate. Hours 11 am to 7 pm of summer weekdays include the highest marginal hourly distribution costs.

To be useful for potential revisions to time of day rates, as well as to guide other time of use rate analyses, EI evaluated a seasonal option where the summer season only includes July and August (Option A). We performed a sensitivity analysis as part of our statistical analysis around the peak hours and determined that a daily on-peak period, 11 am to 7 pm for weekdays provided the highest goodness of fit. This means that the price signals based on these periods are a good fit to the underlying time variation in marginal costs.

EI modelled marginal costs under a second alternative seasonal definition, to test the resulting average marginal costs in the event that the Company considered a less drastic shift towards seasonally differentiated rates. Under Option B, the total system-wide bulk station and distribution station marginal cost estimates would be averaged for a four-month summer period (June-Sep), with the same summer daily peak/off-peak definition as in Option A. Rates based on Option B seasons would produce less efficient price signals since the summer capacity marginal cost would be equally spread across the four months. Tables 1 and 2 below summarize the two alternative costing periods.

Table 1. Alternative Time of Day and Seasonal Periods (Option A)

Seasons		**Time of Use Hours**
Summer (July - August)	*Peak:*	Mo - Fri: 11 am to 7:00 pm; except Holidays
	Off-Peak:	Mo - Fri: 7:00 pm to 11:00 am; Weekends and Holidays: All hours
Winter (Jan – June & Sep-Dec)	*No TOD*	All hours

Table 2. Alternative Time of Day and Seasonal Periods (Option B)

Seasons		**Time of Use Hours**
Summer (June - Sep)	*Peak:*	Mo - Fri: 11:00 am to 7:00 pm; except Holidays
	Off-Peak:	Mo - Fri: 7:00 pm to 11:00 am. Weekends and Holidays: All hours
Winter (Jan – May & Oct – Dec)	*No TOD*	All hours

Table 3 shows the sum of system-wide marginal distribution bulk station and distribution station costs stated on a per-kW-month basis for a secondary-connected customer. The results are shown by peak/off-peak periods using three alternatives. Seasonal average marginal costs on a monthly basis are also shown for the sake of comparison.

Table 3. Time-differentiated System-Wide Marginal per-kW Station Costs

	Marginal Cost of Bulk + Dist. Subs At Secondary Service (2019 $ per kW-mo)	Marginal Cost of Bulk + Dist. Subs At Primary Service (2019 $ per kW-mo)
Current TOU		
Peak	$0.455	$0.453
Off-Peak	$0.004	$0.004
Annual Average	$0.459	$0.457
Option A		
Winter, All hours	$0.017	$0.016
Summer (Jul & Aug) Peak	$2.546	$2.532
Summer (Jul & Aug) Off-Peak	$0.127	$0.127
Winter Average	**$0.017**	**$0.016**
Summer Average (Jul-Aug)	**$2.674**	**$2.659**
Option B		
Winter, All hours	$0.000	$0.000
Summer (June-Sep) Peak	$1.291	$1.283
Summer (June-Sep) Off-Peak	$0.088	$0.087
Winter Average	**$0.000**	**$0.000**
Summer Average (Jun-Sep	**$1.378**	**$1.370**

III. LOCAL DISTRIBUTION FACILITIES

A. Investment

The distribution facilities that are closer to the customers may include primary taps, line transformers and secondary lines. These are less extensively shared. Upon consultation with the Company, we confirmed that Eversource designs these facilities using engineering standards that take into consideration the number of customers who will use those facilities, and those customers' expected maximum loads over the service life of the transformer. Thus, the marginal cost of local distribution facilities is driven by the customer's "design demands", or connected load per customer. This level of kW represents the maximum load that customers may impose on the local system and does not change with variations of actual metered demand from month to month or even year to year.

The Company uses different transformer size standards for customers that use all electric appliances instead of relying partially on oil/gas, or customers with known air conditioning loads. The level of kW may also vary depending on the type of area (rural vs. urban), but specific information by area type was not available.

To estimate the typical installed cost of distribution facilities, Eversource provided an extensive sample of work orders associated with customer connection jobs for single-phase and three-phase customers in the most recent three years (2015-2017). The sample was considered large enough to be representative of the entire service territory. EI reviewed the work orders, and computed the average per kW cost of distribution facilities, after customer contributions as per the line extension policy, as well as average design demand by class. As a measure of design demand, the transformer capacity was divided by the number of customers that are typically served from one transformer, differentiating by rate class and type of service.

B. Operation and Maintenance Expenses

Marginal distribution facility O&M expenses were estimated from historical data (2014-2018) given that there was not a forecast of O&M expenses. The O&M facilities expense per kW of design demand was separated into primary and secondary categories on the basis of miles of circuit. The total design demand was the product of customer counts and per-customer design demand estimates by customer category. EI also estimated the average street lighting O&M expense using per-light average expense over the period 2016-2018 and installed cost of the fixtures expected to be used by street lights going forward.

C. Monthly Facilities Marginal Costs

Table 4 summarizes the monthly marginal local distribution facilities costs, stated as a fixed cost per kW of customer's design demand, and converted into a fixed cost per customer, using the class' average design demand. Table 6 summarizes the monthly marginal customer-related costs by rate class.

Table 4: Summary of Monthly Marginal Local Distribution Facilities Costs by Rate Class

Customer Class	Monthly Facilities Cost per kW of Design Demand	Average Customer Design Demand	Monthly Facilities Cost for the Average Customer
	(2019 $/kW/mo)	(kW-mo)	($/Cust/mo.)
Residential Power & Light	$1.46	11.63	$16.96
Residential OTOD	$1.46	11.63	$16.96
General Service Power & Light 1 Phase	$1.39	19.52	$27.22
General Service Power & Light 3 Phase	$1.99	26.32	$52.26
General Service OTOD 1 Phase	$1.39	19.52	$27.22
General Service OTOD 3 Phase	$1.99	26.32	$52.26
		Average kW/ fixture	
Rate OL	$1.46	0.25	$0.36
Rate EOL	$1.46	0.01	$0.01

IV. MARGINAL CUSTOMER COSTS

A. Meter and Service Drop

Eversource provided the current installed cost of a typical meter by rate class. EI annualized this cost using the appropriate economic carrying charge, as explained in Appendix 1 of this report. EI added an estimate of marginal meter O&M costs, based on recent meter O&M expenses and assuming that the meter O&M is proportional to the cost of the meter in order to estimate meter O&M differentiated by rate class. Appropriate loaders were applied to determine the annual marginal meter cost by class.

The second customer-related cost component is the service drop. The service drop generally serves a single customer. EI estimated the annualized installed cost of the service drop (after customer contributions) for all customer categories. A weighted average installed cost per customer service drop was computed separately for single phase and three phase, as well as by overhead vs. underground, based on customers using each type of service drop by rate class.

B. Customer Accounts and Customer Expenses

Customer accounts expenses, composed mainly of meter-reading and billing expenses, are costs that are the function of a number of customers on the system. The MCOS study relied on weighting factors developed by Eversource for several customer accounts and customer service and informational expenses by class. EI reviewed the average per-customer expense for the period 2014-2018, stated in constant dollars and used as an estimate of future marginal expense of these set of accounts.

C. Monthly Marginal Customer Costs

Table 5 summarizes the monthly marginal customer cost by rate class.

Table 5. Summary of Monthly Marginal Customer Costs by Rate Class

	Marginal Customer Cost ($/Cust/mo.)
Residential Power & Light	$14.91
Residential OTOD	$17.15
Residential Controlled WH	$1.75
Residential LCS	$2.39
Residential Uncontrolled WH	$1.75
General Service Power & Light 1 Phas	$15.04
General Service Power & Light 3 Phas	$32.64
General Service OTOD 1 Phase	$20.06
General Service OTOD 3 Phase	$44.33
General Service Uncontrolled WH	$1.75
General Service LCS 1 Phase	$2.39
General Service LCS 3 Phase	$7.41
General Service Space Heating	$4.52
Rate GV	$1,238.71
Rate GV – (Rate B; < 115 KV level)	$23.15
Rate LG	$1,245.15
Rate LG – (Rate B; < 115 KV level)	$23.67

V. USING MARGINAL COSTS IN UTILITY PRICING

Economic theory holds that economic efficiency is maximized when customers face prices that reflect the marginal costs of using more units of the product or service. In the context of utility distribution service, economic efficiency can be measured as the ability of rates to enable a more efficient use and expansion of the utility's infrastructure and resources, ultimately allowing a lower overall cost of service.

A. Efficient Distribution Marginal-Cost Based Rate Design

System-wide marginal costs are helpful for setting retail rates, both for determining the proper time-differentiation as well as to guide the level of the kWh and kW charges. Cost recovery of sunk costs (the difference between class marginal costs and allocated fixed costs) should primarily be reconciled through the least elastic portions of the bill, namely the basic service charge, to limit the deviation from efficient electricity consumption. An efficient distribution rate structure follows the marginal cost drivers of each component of service:

- Seasonal and time-of-day -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 contract or facility design demand that recovers the marginal costs of local distribution facilities (local primary lines, transformers, secondary lines).

The facility charge may be levied on an estimate of the customer's design demand that reflects the per-kW customer monthly maximum demand or a contract demand that the customer is not expected to exceed at any time. This approach recognizes the more fixed nature of the costs of the transformers, which are sized to serve the long-term maximum demands of the few customers connected to it. Transformers and local lines are installed with sufficient capacity so that they do not need to be expanded as the local load grows, except for unusual circumstances.

Recovering marginal facilities costs through a monthly fixed charge (calculated on the basis of the class average design demand) may be appropriate if there are not significant differences in customer kW size within the rate class. When adopting a fixed monthly fixed charge it is best to differentiate within the class separating subgroups with homogeneous loads such as all-electric residential customers vs. gas heating customers.

B. Marginal Cost Use for DER and NEM Evaluation

Time-differentiated marginal costs associated with the upstream distribution grid over the upcoming utility's planning period provide useful information to evaluate and design DER pricing models. An important goal in determining distribution rates for DERs is to ensure that these resources are connected to the utility system in the most efficient way possible and to avoid uneconomic bypass, which would increase the overall cost of service.

Marginal cost information is important to provide the right incentives to locate where and when those resources can bring the most value to the system. Following the marginal cost structure of distribution service involves separating the costs that are associated with local facilities from those that are time-related. In the case of Eversource, the MCOS results suggest that the highest primary distribution value of DER ouput is concentrated on mid-day to 7:00 pm in July and August. The system-wide time-differentiation results obtained in this MCOS study under Option A provide a reasonable basis upon which to inform DER compensation.

Ultimately, rates for DG customers need to contribute to cost recovery in a manner that is aligned with the costs they incrementally caused to the system, which may be higher or lower than regular customers. The cost allocation should be comparable to those of non-DER customers but the price mechanism may need to be different to avoid the limitations that may be present with excessive simplification of the standard rates.

C. Summary of Marginal Unit Costs by Customer Class

In order to evaluate the efficiency in the existing distribution price signals, it is useful to compare them with marginal unit costs. Table 6 summarizes the marginal cost results following the structure of Eversource's existing distribution rates, i.e., using the TOU periods as in current TOD rates.

Primary distribution costs are stated on both demand and an energy basis. For maximum efficiency in price signals, these rate components should be time-differentiated by time of day and season. The local distribution facilities costs are shown in two alternative ways – per customer and per kW of monthly design or contract demand since these costs do not change with kWh usage or near-term changes in customer metered peak load. While these cost figures have not been marked up to reflect the class revenue targets, they are useful to assess the efficiency of the price signals in the current rates.

We note that the figures reflect marginal unit costs for each component of service, with no reconciliation for revenue targets. A mark-up to the components would be necessary to capture the class allocated revenue requirement.

Table 6. Marginal Costs for 2020-2024 averaged according to Existing Rate Structures

		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

APPENDIX 1: DERIVATION OF ANNUAL MARGINAL COSTS

ANNUALIZATION PROCESS

This Appendix includes the explanation of the various steps to derive the annualized bulk station, distribution substation and primary feeder costs, the annualized marginal cost for local primary and secondary distribution facilities, marginal cost per lighting fixture, and the annualized cost of meters and service drop by rate class.

The MCOS estimated annualized marginal cost for each component of service by multiplying the marginal investments for each plant type by the annual economic carrying charge, expressed as a percentage. The marginal investment is adjusted using a general plant loading factor and a plant-related A&G loading factor.

Converting estimates of marginal distribution plant investment into annual costs for use in rate design and other cost analysis, requires estimating an economic carrying charge (ECC). The first year ECC represents today's market or "rental" value per kW. Subsequent years' ECC are calculated by applying annual inflation in such a way that the present value of the stream of annual revenues equals the present value of the revenue requirement associated with owning the asset.

To these costs, EI added marginal O&M expenses, adjusted by non-plant related A&G expenses. Revenue requirement for working capital including cash, materials, supplies and prepayments is also added to obtain the annualized marginal costs of different types of plant.

A summary of the calculation of these components is provided below.

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE
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TABLE A.1.1. DERIVATION OF ANNUAL BULK AND NON-BULK SUBSTATION COST

Line		System-Wide Average of Marginal Cost		MCs in Capacity-Expanding Areas	
7		Bulk Station	Non-bulk Substation	Bulk Station	Non-bulk Substation
8		(2019 $/kW)	(2019 $/kW)	(2019 $/kW)	(2019 $/kW)
10	Locational marginal Investment per kW of				
11	added peak load carrying capability (2020-2024)	$182.51	$250.60	$182.51	$250.60
12	Share of total retail peak load at expanding stations	20.3%	5.5%		
13	Share of total retail load fed from station type	98.2%	17.5%		
14	System-wide marginal Investment per kW of Peak Loac	$36.33	$2.41		
15	Economic Carrying Charge	8.43%	8.43%	8.43%	8.43%
16	General Plant Loader	1.0697	1.0697	1.0697	1.0697
17	Plant-related A&G Loader	1.0002	1.0000	1.0000	1.0000
18	Subtotal Annualized Capital Costs	$3.28	$0.22	$16.46	$22.60
19	O&M Expenses				
20	Annual Marginal O&M Expenses per kW of Peak Loa	$1.51	$0.07	$7.45	$7.57
21	A&G Loading 1.049 (Non-plant Related)	1.049	1.049	1.049	1.049
22	Working Capital Revenue Requirement				
23	Material, Supplies and Prepayments	$0.066	$0.004	$0.330	$0.453
24	Cash Working Capital Allowance	$0.020	$0.001	$0.098	$0.100
25	**Total Annualized Marginal Station Cost ($/kW-yr)**	**$4.94**	**$0.30**	**$24.70**	**$31.09**

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TABLE A.1.2. DERIVATION OF ANNUAL DISTRIBUTION FACILITIES COSTS

	R-P&L	R-OTOD	R-C-WH	R-UC-WH	R-LCS	GS-P&L-P1	GS-P&L-P3	GS-OTOD-P1	GS-OTOD-P3	GS-UC-WH	GS-LCS-P1	GS-LCS-P3	GS-SH	OL	EOL
	Residential Power & Light	**Residential OTOD**	**Residential Controlled WH**	**Residential Uncontrolled WH**	**Residential LCS**	**General Service Power & Light 1 Phase**	**General Service Power & Light 3 Phase**	**General Service OTOD 1 Phase**	**General Service OTOD 3 Phase**	**General Service Uncontrolled WH**	**General Service LCS 1 Phase**	**General Service LCS 3 Phase**	**General Service Space Heating**	**Rate OL**	**Rate EOL**
	---------------- (2019 Dollars per kW of Design Demand) ----------------														
Marginal Investment per kW of Design Demand															
after customer contributions ($/kW)	$118.24	$118.24	$118.24	$118.24	$118.24	$118.24	$189.85	$118.24	$189.85	$118.24	$118.24	$189.85	$118.24	$118.24	$118.24
General Plant Loading	1.070	1.070	1.070	1.070	1.070	1.070	1.070	1.070	1.070	1.070	1.070	1.070	1.070	1.070	1.070
Annual Economic Carrying Charge	9.09%	9.09%	9.09%	9.09%	9.09%	9.09%	9.09%	9.09%	9.09%	9.09%	9.09%	9.09%	9.09%	9.09%	9.09%
Annualized Costs	$11.50	$11.50	$11.50	$11.50	$11.50	$11.50	$18.46	$11.50	$18.46	$11.50	$11.50	$18.46	$11.50	$11.50	$11.50
Annual O&M Expense per kW of Design Demand															
With A&G Loading x 1.0487															
	5.71	5.71	5.71	5.71	5.71	4.96	4.96	4.96	4.96	4.96	4.96	4.96	4.96	5.71	5.71
Subtotal Distribution Facilities Marginal Costs	$17.21	$17.21	$17.21	$17.21	$17.21	$16.46	$23.42	$16.46	$23.42	$16.46	$16.46	$23.42	$16.46	$17.21	$17.21
<u>Working Capital Rev. Req.</u>															
Material, Supplies and Prepayments	0.21	0.21	0.21	0.21	0.21	0.21	0.34	0.21	0.34	0.21	0.21	0.34	0.21	0.21	0.21
Cash Working Capital Allowance	0.07	0.07	0.07	0.07	0.07	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.07	0.07
Total Annualized Marginal Facilities															
Cost per kW of Design Demand ($/kW-yr)	**$17.50**	**$17.50**	**$17.50**	**$17.50**	**$17.50**	**$16.74**	**$23.83**	**$16.74**	**$23.83**	**$16.74**	**$16.74**	**$23.83**	**$16.74**	**$17.50**	**$17.50**

Line		R-P&L	R-OTOD	R-C-WH	R-LCS	R-UC-WH	GS-P&L-P1	GS-P&L-P3	GS-OTOD-P1	GS-OTOD-P3	GS-UC-WH	GS-LCS-P1	GS-LCS-P3	GS-SH
1	**PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE**													
2	**D/B/A, EVERSOURCE ENERGY**													
3	**TABLE A.1.3. ANNUAL CUSTOMER-RELATED MARGINAL UNIT COST**													
4	**RESIDENTIAL AND GENERAL SERVICE**													
5														
6														
7		**R-P&L**	**R-OTOD**	**R-C-WH**	**R-LCS**	**R-UC-WH**	**GS-P&L-P1**	**GS-P&L-P3**	**GS-OTOD-P1**	**GS-OTOD-P3**	**GS-UC-WH**	**GS-LCS-P1**	**GS-LCS-P3**	**GS-SH**
8		**Residential Power & Light**	**Residential OTOD**	**Residential Controlled WH**	**Residential LCS**	**Residential Uncont. WH**	**GS P&L 1 Phase**	**GS P&L 3Phase**	**GS OTOD 1 Phase**	**GS OTOD 3 Phase**	**GS Uncont. WH**	**GS LCS 1 Phase**	**GS LCS 3 Phase**	**GS Space Heating**
9							---------------- (2019 Dollars per Customer) ----------------							
10	Meter													
11	Installed Meter Cost	$57.35	$152.35	$57.35	$57.35	$57.35	$57.35	$269.69	$269.69	$764.07	$57.35	$57.35	$269.69	$169.96
12	With General Plant Loading	$61.34	$162.96	$61.34	$61.34	$61.34	$61.34	$288.49	$288.49	$817.33	$61.34	$61.34	$288.49	$181.81
13	Annual ECC related to Capital Investment	9.37%	9.37%	9.37%	9.37%	9.37%	9.37%	9.37%	9.37%	9.37%	9.37%	9.37%	9.37%	9.37%
14	Subtotal Annualized Meter Costs	$5.75	$15.27	$5.75	$5.75	$5.75	$5.75	$27.03	$27.03	$76.57	$5.75	$5.75	$27.03	$17.03
15	Meter O&M Expenses with A&G Loading	$10.29	$27.33	$10.29	$10.29	$10.29	$10.29	$48.38	$48.38	$137.07	$10.29	$10.29	$48.38	$30.49
	Service drop													
16	Installed Service Cost													
17	With General Plant Loading x 1.0697	$1,090.18	$1,090.18	-	-	-	$1,090.18	$2,718.40	$1,090.18	$2,718.40	-	-	-	-
18	Annual ECC related to Capital Investment	9.09%	9.09%	9.09%	9.09%	9.09%	9.09%	9.09%	9.09%	9.09%	9.09%	9.09%	9.09%	9.09%
19	Annualized Service Drop Costs	99.12	99.12	-	-	-	99.12	247.15	99.12	247.15	-	-	-	-
20	Customer services													
21	Customer Accounts Expenses	$57.77	$57.77	$4.41	$11.71	$4.41	$59.286	$59.286	$59.286	$59.286	$4.4	$11.6	$11.6	$5.7
22	Customer Service & Informational Expenses	$0.16	$0.16	$0.00	$0.00	$0.00	$0.159	$0.159	$0.159	$0.159	$0.0	$0.0	$0.0	$0.0
23	With non-plant A&G Loading x 1.0487	$60.75	$60.75	$4.63	$12.28	$4.63	$62.34	$62.34	$62.34	$62.34	$4.63	$12.20	$12.20	$5.96
24	**Sub-total Annualized Cost of Meter, Service and Customer Expenses**	$175.90	$202.46	$20.66	$28.31	$20.66	$177.49	$384.89	$236.86	$523.12	$20.66	$28.23	$87.60	$53.48
25	Working Capital Rev. Req.													
26	Material, Supplies and Prepayments	$2.08	$2.26	$0.11	$0.11	$0.11	$2.08	$5.43	$2.49	$6.39	$0.11	$0.11	$0.52	$0.33
27	Cash Working Capital	$0.89	$1.11	$0.19	$0.28	$0.19	$0.91	$1.39	$1.39	$2.51	$0.19	$0.28	$0.76	$0.46
28	**Total Annual Customer Marginal Costs**	**$178.87**	**$205.83**	**$20.96**	**$28.71**	**$20.96**	**$180.48**	**$391.72**	**$240.74**	**$532.01**	**$20.96**	**$28.62**	**$88.88**	**$54.26**

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE
D/B/A, EVERSOURCE ENERGY
TABLE A.1.4. ANNUAL CUSTOMER-RELATED MARGINAL UNIT COST
MIDDLE AND LARGE GENERAL SERVICE CUSTOMERS

	GV	LG
Meter		
Installed Meter Cost	$709.00	$726.82
With General Plant Loading x 1.0697	$758.42	$777.48
Annual ECC related to Capital Investment	9.37%	9.37%
Annualized Meter Costs	$71.05	$72.83
Meter O&M Expenses with A&G loading	$127.19	$130.39
Customer services		
Customer Accounts Expenses	$544.86	$612.92
Customer Service & Informational Expenses	$13,264.01	$13,264.01
With non-plant A&G Loading x 1.0487	$14,481.37	$14,552.73
Sub-total Annualized Cost of Meter and Customer Expenses	$14,679.60	$14,755.95
Working Capital Rev. Req.		
Material, Supplies and Prepayments	$1.37	$1.40
Cash Working Capital	$183.52	$184.46
Total Annual Customer Marginal Costs	**$14,864.49**	**$14,941.82**

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

D/B/A, EVERSOURCE ENERGY

TABLE A.1.5. ANNUAL CUSTOMER-RELATED MARGINAL COST FOR STREET LIGHTING

	Rate OL			Rate EOL
	HP-Sodium	Metal Halide	LED	LED
Service drop				
Installed Service Cost	$61.61	$56.81	22.41	22.41
With General Plant Loading x 1.0697	$65.91	$60.77	$23.98	$23.97
Annual ECC related to Capital Investment	9.09%	9.09%	9.09%	9.09%
Annualized Service Drop Costs	$5.99	$5.52	$2.18	$2.18
Customer services				
Customer Accounts Expenses	$26.76	$26.76	$26.76	$18.30
Customer Service & Informational Expenses	$0.00	$0.00	$0.00	$0.00
With non-plant A&G Loading x 1.0487	$28.06	$28.06	$28.06	$19.19
Sub-total Annualized Cost of Service Drop and Customer Service	$34.05	$33.59	$30.24	$21.37
Working Capital Rev. Req.				
Material, Supplies and Prepayments	$0.12	$0.11	$0.04	$0.04
Cash Working Capital	$0.35	$0.35	$0.35	$0.24
Total Annual Customer Marginal Costs	**34.52**	**34.05**	**30.64**	**21.66**

APPENDIX 2: MCOSS SUPPORTING WORKSHEETS

Table A.2.1 Marginal Investment in Bulk Substations (2020-2024)

Region	2019	2020	2021	2022	2023	2024	Total (2019$)	Existing Capacity	New	Added	Average Cost per kW added	Average Cost per added Carrying Capability
				(000 $), $2019					MW		$/kW	$/kW
Total Bulk Investment (Peak Related)	2,500.00	9,000.00	5,000.00	5,000.00	4,000.00	2,000.00	$27,500	451.2	652.1	200.9	$136.88	$182.51

Table A.2.2 Marginal Investment in Non-Bulk Substations (2020-2024)

	2021	2022	2023	2024	Total (2019$)	Existing Capacity	New	Added	Average Cost per Added Carrying Capability
						MW	MW	MW	$/kW
Total Non-Bulk Investment (Peak Related)	400.00	1,600.00	1,600.00	1,600.00	5,200	16.8	37.5	20.8	$250.60

Table A.2.3 Retail Peak Load-Share in Areas of Capacity Expansion Need

	Year 2024
Total Retail Peak served from Bulk Stations (a)	1,973.25
Total Retail Peak Load in Capacity Expansion Need Areas (b)	399.78
Ratio (b)/(a)	*20.26%*

Table A.2.4 Marginal O&M Expenses of Bulk Station and Non-Bulk Substation Peak Load

Bulk Distribution Station O&M	*Year* 2014	2015	2016	2017	2018	Average
Annual Bulk Station O&M Expenses (000 Dollars)	$14,630.27	$15,193.45	$15,563.97	$14,831.24	$16,318.65	
Weather- normalized Bulk Station NCP (MW)	2,244	2,284	2,126	2,237	2,262	
O&M expense per kW of Bulk Station Peak Load	$6.52	$6.65	$7.32	$6.63	$7.22	
Weighted Labor and Materials Cost Index (2019=1.00)	0.88	0.90	0.91	0.94	0.98	
Bullk Station O&M expense per kW of Peak Load (2019 Dollars)	$7.39	$7.38	$8.03	$7.06	$7.37	
Marginal Station O&M Expense per kW of Peak Load in Areas of Growth over 2020-2024 ($/kW-yr)						$7.45
Station Peak-load Share in areas of capacity expansion						20.26%
System-wide Marginal Bulk Station O&M Expense ($/kW-yr)						**$1.51**

Non-Bulk Distribution Station O&M	*Year* 2014	2015	2016	2017	2018	Average
Annual Distribution Subst. and Trunkline O&M Expenses (000 Dollars)	$2,217.72	$2,303.09	$2,359.25	$2,248.18	$2,398.91	
Weather-normalized Dist. Substation NCPs (MW)	335	341	317	334	327	
O&M expense per kW of Dis. Substation Peak Load (2019 $/kW)	$6.63	$6.76	$7.44	$6.74	$7.33	
Weighted Labor and Materials Cost Index (2019=1.00)	0.88	0.90	0.91	0.94	0.98	
Dis. Substation O&M expense per kW of Peak Load (2019 $/kW)	$7.51	$7.50	$8.16	$7.18	$7.49	
Marginal Station O&M Expense per kW of Peak Load in Areas of Growth over 2020-2024 ($/kW-yr)						$7.57
Station Peak-load Share in areas of capacity expansion						5.51%
System-wide Marginal Distribution Substation O&M Expense ($/kW-yr)						$0.42
Share of the Company load served from a distribution substation						17.46%
System-wide Marginal Distribution Station O&M Expense ($/kW-yr)						**$0.07**

Table A.2.5. Bulk and Non-Bulk Station Costs by TOU Periods and Seasons (Current Periods)

Current TOU Periods

Probability of System Peak:

Year-Round **Peak**	Year-Round **Off-Peak**
99.2%	**0.8%**

	Bulk Substation		**Dist. Substation**	
	Year-round		**Year-round**	
	Peak	**Off-Peak**	**Peak**	**Off-Peak**
Losses Through Levels				
Secondary	1.0518	1.0518	1.0417	1.0417
Primary	1.0460	1.0460	1.0360	1.0360
Annual MC (System Wide-Average)				
$/kW-yr (Total)	4.94		0.30	
$/kW-yr (Costing Period)	4.9029	0.0417	0.30	0.00
$ per kW per month	0.4086	0.0035	0.0247	0.0002
Hours by Costing Period	3,246	5,514	3,246	5,514
$/kWh	0.0015	0.0000	0.0001	0.0000
Cost per kWh ($/kWh)				
Secondary Cost adjusted by losses	0.0016	0.0000	0.0001	0.0000
Primary Cost	0.0016	0.0000	0.0001	0.0000
Cost per kW ($/kW-mo)				
Secondary Cost adjusted by losses	0.4298	0.0037	0.0257	0.0002
Primary Service	0.4274	0.0036	0.0256	0.0002

Table A.2.6. Bulk and Non-Bulk Station Costs by TOU Periods and Seasons (Option A Periods)

Option A - TOU

Probability of Distribution System Peak:

Peak Summer (July & August)		All Other Months
Peak	**Off-Peak**	**All Hours**
92.38%	4.62%	2.99%

	Bulk Substation			Dist. Substation		
	Summer		Winter	Summer		Winter
	Peak	Off-Peak	All Hours	Peak	Off-Peak	All Hours
Losses Through Levels						
Secondary	1.0518	1.0518	1.0518	1.0417	1.0417	1.0417
Primary	1.0460	1.0460	1.0460	1.0360	1.0360	1.0360
Annual MC (System Wide-Average)						
$/kW-yr (Total)		4.94			0.30	
$/kW-yr (Costing Period)	4.5679	0.2287	0.1481	0.2761	0.0138	0.0090
$ per kW per month	2.2840	0.1143	0.0148	0.1381	0.0069	0.0009
Hours by Costing Period	341	1,123	7,296	341	1,123	7,296
$/kWh	0.0134	0.0002	0.0000	0.0008	0.0000	0.0000
Cost per kWh ($/kWh)						
Secondary Cost adjusted by losses	0.0141	0.0002	0.0000	0.0008	0.0000	0.0000
Primary Cost	0.0140	0.0002	0.0000	0.0008	0.0000	0.0000
Cost per kW ($/kW-mo)						
Secondary Cost adjusted by losses	2.4024	0.1203	0.0156	0.1438	0.0072	0.0009
Primary Service	2.3891	0.1196	0.0155	0.1430	0.0072	0.0009

Table A.2.7. Bulk and Non-Bulk Station Costs by TOU Periods and Seasons (Option B Periods)

Option B - TOU

Probability of Distribution System Peak:

Summer (June - Sep)		All Other Months
Peak	**Off-Peak**	**All Hours**
93.65%	6.35%	0.000%

	Bulk Substation			Dist. Substation		
	Summer		Winter	Summer		Winter
	Peak	Off-Peak	All Hours	Peak	Off-Peak	All Hours
Losses Through Levels						
Secondary	1.0518	1.0518	1.0518	1.0417	1.0417	1.0417
Primary	1.0460	1.0460	1.0460	1.0360	1.0360	1.0360
Annual MC (System Wide-Average)						
$/kW-yr (Total)		4.94			0.30	
$/kW-yr (Costing Period)	4.6305	0.3141	0.00	0.2799	0.0190	0.0000
$ per kW per month	1.1576	0.0785	0.00	0.0700	0.0047	0.0000
Hours by Costing Period	681	2,247	5,832.00	681	2,247	5,832
$/kWh	0.0068	0.0001	0.00	0.0004	0.0000	0.0000
Cost per kWh ($/kWh)						
Secondary Cost adjusted by losses	0.0072	0.0001	0.00	0.0004	0.0000	0.0000
Primary Cost	0.0071	0.0001	0.00	0.0004	0.0000	0.0000
Cost per kW ($/kW-mo)						
Secondary Cost adjusted by losses	1.2177	0.0826	0.00	0.0729	0.0049	0.0000
Primary Service	1.2109	0.0821	0.00	0.0725	0.0049	0.0000

Table A.2.8 Installed Cost of Single-Phase Distribution Facilities

Construction Type	Average Gross Facilities Cost per kVA (2019$)	Average Facilities Cost (after CIAC) per KVA (2019$)	Average OH/UG split	Average Transformer Size (kVA)	No. of Residential customers per transformer 1-ph	Average kVA per Customer (residential)	No. of GS 1-ph Customers per Transformer	Average kVA per Customer (GS)
UG 1 PH	$174.04	$126.77	0.21	**50**	2.6	19.23	1.55	32.26
OH 1 PH	$191.79	$115.98	0.79	**25**	2.6	9.62	1.55	16.13
Average Cost (after CIAC)		**$118.24**			Weighted Average kVA (1-ph)	**11.63**	Weighted Average kVA (1-ph)	**19.52**

Table A.2.9 Installed Cost of Three-Phase Distribution Facilities

Construction Type	Average Gross Facilities Cost per kVA (2019$)	Average Net Facilities Cost (after CIAC) per KVA (2019$)	Average OH/UG split	Average Transformer Cost per kVA (2019$)	Median Transformer Size (KVA)	Max Size (KVA)	No. of customers per transformer GS-3ph	kVA per GS Customer	
UG	$168.87	$141.26	0.39	$80.77	50.0	175.0	1.9	26.32	
OH	$229.67	$220.91	0.61	$84.49	50.0	150.0	1.9	26.32	
Average Cost (After CIAC)			**$189.85**				Weighted Average kVA (3-ph)	**$26.32**	**kVA**

Table A.2.10 Marginal O&M Expenses for Distribution Facilities

	Year 2014	2015	2016	2017	2018	Average
Secondary Portion of Distribution Facility O&M Expenses (000's Dollars)	$4,290.6	$3,968.8	$4,397.1	$4,253.5	$4,105.1	
Primary Portion of Distribution Facility O&M Expenses (000's Dollars)	$25,939.3	$28,609.9	$32,561.3	$29,665.4	$31,227.8	
Design Demand on Secondary (MW)	6,552	6,544	6,605	6,674	6,757	
Design Demand on Primary (MW)	6,704	6,696	6,758	6,829	6,914	
Weighted Labor and Materials Cost Index (2019 = 1.00)	0.88	0.90	0.91	0.94	0.98	
Secondary Distribution Facilities O&M Expense Per kW of Design Demand (2019 Dollars/kW)	$0.74	$0.67	$0.73	$0.68	$0.62	
Primary Distribution Facilities O&M Expense Per kW of Design Demand (2019 Dollars/kW)	$4.38	$4.74	$5.28	$4.63	$4.61	
Annual Primary Distribution Facilities O&M Expense per kW for Primary Customer ($/kW-yr)						**$4.73**
Total Annual Primary and Secondary Distribution Facilities O&M Expense per kW for Secondary Customer ($/kW-yr)						**$5.45**

Table A.2.11 Lighting O&M per Light

	2017	2018	Average
Total Lighting Operation & Maintenance Expenses ('000 Dollars)	$633	$641	
Number of ST Lights	25,770	25,770	
O&M Expenses Per Light (Dollars)	24.56	24.88	
Weighted Labor and Materials Cost Index (2019=1.00)	93.88	97.92	
Lighting Expense Per Light (2019 Dollars)	0.26	0.25	
Estimated Annual Weighted Lighting O&M Expense for Planning Period			**$0.26**

Table A.2.12 Annualized ST Fixture Cost

HP SODIUM

	50W	70	100	150	250	400	1,000
	(2019 Dollars per fixture)						
Marginal Investment per fixture	$435	$433	$459	$465	$532	$683	$1,100
With General Plant Loading x 1.0697	$465.84	$462.88	$490.67	$497.71	$568.83	$730.28	$1,176.38
Annual Economic Carrying Charge Related to Capital Investment	11.10%	11.10%	11.10%	11.10%	11.10%	11.10%	11.10%
Annualized Costs	$51.72	$51.39	$54.48	$55.26	$63.15	$81.08	$130.61
Lighting O&M Expenses	$0.26	$0.26	$0.26	$0.26	$0.26	$0.26	$0.26
With A&G Loading x 1.0487 (non-plant related)	$0.27	$0.27	$0.27	$0.27	$0.27	$0.27	$0.27
Annual Fixture-related Costs	$51.99	$51.66	$54.75	$55.53	$63.43	$81.35	$130.88
Working Capital							
Material and Supplies	$4.50	$4.47	$4.74	$4.81	$5.49	$7.05	$11.36
Prepayments	$3.88	$3.85	$4.08	$4.14	$4.73	$6.08	$9.79
Cash Working Capital Allowance	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03
Total Working Capital	$8.41	$8.35	$8.85	$8.98	$10.26	$13.16	$21.18
Revenue Requirement for Working Capital	$0.85	$0.84	$0.89	$0.90	$1.03	$1.32	$2.13
Total Annual Marginal Per-Light Cost	**$52.84**	**$52.50**	**$55.64**	**$56.43**	**$64.46**	**$82.67**	**$133.01**

METAL HALIDE

	50 W	70 W	100 W	175	250 W	400 W	1,000
	(2019 Dollars per fixture)						
Marginal Investment per fixture	$471	$510	$497	$522	$561	$684	$1,135
With General Plant Loading x 1.0697	$503.36	$545.49	$531.57	$557.92	$600.02	$732.19	$1,213.68
Annual Economic Carrying Charge Related to Capital Investment	11.10%	11.10%	11.10%	11.10%	11.10%	11.10%	11.10%
Annualized Costs	$55.89	$60.56	$59.02	$61.94	$66.62	$81.29	$134.75
Lighting O&M Expenses	$0.26	$0.26	$0.26	$0.26	$0.26	$0.26	$0.26
With A&G Loading x 1.0487 (non-plant related)	$0.27	$0.27	$0.27	$0.27	$0.27	$0.27	$0.27
Annual Fixture-related Costs	$56.16	$60.83	$59.29	$62.21	$66.89	$81.56	$135.02
Working Capital							
Material and Supplies	$4.86	$5.27	$5.13	$5.39	$5.79	$7.07	$11.72
Prepayments	$4.19	$4.54	$4.42	$4.64	$4.99	$6.09	$10.10
Cash Working Capital Allowance	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03
Total Working Capital	$9.08	$9.84	$9.59	$10.06	$10.82	$13.20	$21.85
Revenue Requirement for Working Capital	$0.91	$0.99	$0.96	$1.01	$1.09	$1.33	$2.20
Total Annual Marginal Per-Light Cost	**$57.07**	**$61.82**	**$60.25**	**$63.23**	**$67.98**	**$82.89**	**$137.22**

LED LIGHTS

	50 W	75 W	100 W	150 W	250 W	400 W
	(2019 Dollars per fixture)					
Marginal Investment per fixture	$606.08	$594.97	$602.72	$651.33	$715.96	$942.17
With General Plant Loading x 1.0697	$648.33	$636.44	$644.73	$696.72	$765.86	$1,007.84
Annual Economic Carrying Charge Related to Capital Investment	11.10%	11.10%	11.10%	11.10%	11.10%	11.10%
Annualized Costs	$71.98	$70.66	$71.58	$77.35	$85.03	$111.90
Lighting O&M Expenses	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
With A&G Loading x 1.0487 (non-plant related)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Annual Fixture-related Costs	$71.98	$70.66	$71.58	$77.35	$85.03	$111.90
Working Capital						
Material and Supplies	$6.26	$6.15	$6.23	$6.73	$7.40	$9.73
Prepayments	$5.39	$5.30	$5.36	$5.80	$6.37	$8.39
Cash Working Capital Allowance	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total Working Capital	$11.66	$11.44	$11.59	$12.53	$13.77	$18.12
Revenue Requirement for Working Capital	$1.17	$1.15	$1.16	$1.26	$1.38	$1.82
Total Annual Marginal Per-Light Cost	**$73.15**	**$71.81**	**$72.75**	**$78.61**	**$86.41**	**$113.72**

Table A.13. Meter O&M Expense

	2014	2015	2016	2017	2018	Average of 2016-2018
Total Meter O&M Expenses (000's Dollars)	$5,218.5	$6,886.5	$6,868.5	$6,238.0	$4,949.7	
Number of Metered Accounts	556,182	554,127	557,589	561,881	567,397	
Weighted Number of Accounts	647,202	644,811	648,839	653,834	660,252	
Meter Expense Per Weighted Account (Nominal dollars)	8.06	10.68	10.59	9.54	7.50	
Weighted Labor and Materials Cost Index (2019 = 1.00)	0.88	0.90	0.91	0.94	0.98	
Meter Expense Per Weighted Account (2019 Dollars)	$9.14	$11.86	$11.61	$10.16	$7.66	
Estimated Annual Weighted Meter O&M Expense						**$9.8**

Table A.2.14 Customer Account Expense per Weighted Customer Numbers

Customer Account Expense Calculation	2014	2015	2016	2017	2018	Average 2016-2018
Total Customer Accounts Expense (000's Dollars)	$32,405.1	$34,225.9	$29,651.4	$28,814.3	$28,563.9	
Annual Number of Accounts	557,145	555,082	558,529	562,695	568,170	
Weighted Average Number of Accounts	527,594	525,641	528,905	532,850	538,035	
Customer Accounts Expense Per Weighted Account	$61.42	$65.11	$56.06	$54.08	$53.09	
Labor Cost Index (2019 = 1.00)	0.86	0.89	0.92	0.94	0.97	
Customer Accounts Expense Per Weighted Customer (2019 Dollars	$71.20	$73.28	$61.26	$57.37	$54.68	
Estimated Annual Weighted Customer Accounts Expense						**$57.77**

Table A.2.15 Customer Service and Informational Expense per Weighted Customer Numbers

Customer Service & Informational Expense Calculation	2014	2015	2016	2017	2018	Average 2014-2018
Total Customer Service and Informational Expense (000's Dollars)	$17,562.30	$16,025.58	$16,145.63	$16,301.44	$23,327.79	
Average Number of Customers	503,999	503,280	508,002	513,304	519,583	
Weighted Average Number of Customers	121,197,265	121,024,366	122,159,871	123,434,850	124,944,861	
Customer Service and Informational Expense Per Weighted Custor	$0.14	$0.13	$0.13	$0.13	$0.19	
Labor Cost Index (2019 = 1.00)	0.86	0.89	0.92	0.94	0.97	
Customer Service and Informational Expense Per Weighted Custor	$0.17	$0.15	$0.14	$0.14	$0.19	
Estimated Annual Weighted Customer Service and Informational Expense						**$0.16**