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Eversource Energy's Marginal Cost of Distribution Service Study and Use for Efficient Rates

Prepared for the Public Service Company of New Hampshire

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EXECUTIVE SUMMARY

A. Introduction

Eversource Energy ("Eversource", or "The Company"), retained Economists Incorporated (EI) to develop a marginal cost of service (MCOS) study for the Company's electricity distribution service in New Hampshire. EI has developed a forward-looking MCOS study that takes into account the Company's prevailing engineering design standards and planning process.

Marginal cost is defined as the change in total cost of service with respect to a small change in the demand of a product or service at any given time. It also represents the value of those resources in their next best alternative use, known as the opportunity cost. Marginal distribution cost estimation requires evaluating Eversource's response, from a planning perspective, to anticipated increments of peak load usage or changes to customer service requirements.

The results of the MCOS study will be helpful to inform Eversource's distribution rate designs. There is growing interest in New Hampshire in customer-sited rooftop solar and other DERs such as potentially customer-sited battery storage. Increased awareness of the value that these resources may bring to the distribution system requires a marginal cost analysis of the type that has been undertaken in this MCOS study.

B. Main Elements of the MCOS Approach

The MCOS study uses a five-year period for the analysis of marginal costs, which is generally consistent with Eversource's system planning timeframe. The study also takes into account the specific configuration of Eversource's distribution system, the current connection charge policies (which affect the net marginal costs to be recovered in tariffs), and other factors such as the specific utility capital cost structure.

The main elements of EI's MCOS study approach are summarized below.

- ***High voltage distribution***: Eversources' higher voltage segment of the delivery system (bulk stations, distribution substations, and trunkline feeders) are designed and constructed to meet expected near-term growth of diversified peak demand at the station level. The MCOS study starts by identifying the marginal costs of growth-related investments in these elements of distribution plant for the upcoming five-year period (2019-2023). To be useful for rate design, the MCOS then converts the averaged marginal station cost corresponding to capacity constrained areas into a system-wide marginal cost per kW of station peak load. This step recognizes that not all areas of Eversource's service territory will need capacity expansion to meet future peak loads. These costs are then annualized, adjusted appropriately by losses, and allocated to all hours of the year based on probability of peak factors.

- ***Local Facilities:*** The second part of the study includes the lower-voltage distribution facilities that connect customers to the main grid. EI confirmed with distribution planners that decisions on the required size of the transformers, local primary and secondary lines primarily take into account the expected customer's long term, non-coincident demands over the service life of these facilities. The MCOS study reflects this segmentation of utility investment cost drivers for the estimation approach. EI analyzed these costs using a review of connection costs in work orders and estimates of class' typical design demand.

- ***Customer-related costs***: 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. EI's MCOS estimates the annualized installed cost of these assets for all customer categories and adds the corresponding marginal O&M and customer service expenses to compute monthly marginal customer-costs. As part of this analysis, street lighting marginal costs are also computed, taking into account typical investment per fixture.

The study summarizes the marginal cost results by customer class. Because the MCOS study identifies the different cost drivers of elements of the distribution system, the marginal cost results inform on the appropriate relationships between customer charge and other rate components. The MCOS study summarizes hourly marginal distribution station costs by pricing periods suitable for the design of TOU and seasonal tariffs. In this regard, rates should reflect a signal regarding the hours and months when serving electricity to the customer has the highest opportunity cost to the utility, such as the need to expand distribution infrastructure to meet the load.

C. Key Findings of Marginal Costs and Implications for Rate Design

The main findings from the MCOS study in relation to applications for rate design are as follows:

- Marginal costs associated with peak load growth will be relatively low in the foreseeable planning period. The current per-kWh charges in Eversource's NH distribution rates generally exceed the per-kWh marginal costs of upstream distribution service, suggesting an artificially high incentive to conserve system-wide. This is exacerbated by the fact that there is currently no seasonality in the energy or demand charges of any of the distribution rates.

- The broad peak period in existing TOD distribution rates (7:00 am to 8:00 pm, during weekdays) is not justified by the current and expected system-wide distribution hourly load patterns. Our review of historical station hourly loads suggests the need to narrow the peak period down to no more than an 8-hour window (noon to 8 pm) in summer weekdays and to consider all other summer hours and all other months as off-peak. In addition, the summer season may need to be limited to the months of July and August, which account for the majority of the annual probability of peak.

- The drivers of distribution facilities such as service transformers are for the most part unrelated to on-going increases in customer energy usage; thus, recovery of marginal local distribution facilities costs is more efficiently done through a separate facility charge on the basis of a measure of customer design demand, or through an increase in the customer charge, instead of including it in the per-kWh charge.

D. Use of Marginal Costs for DER Evaluation and Net Metering Pricing Alternatives

Ideally, compensation for the DER's performance would be linked to the peak hours on the distribution station, where applicable. This is because it is only in those hours when any DER-driven load reduction may play a meaningful role in reducing capacity needs and peak losses. Flat, non-seasonally differentiated distribution rates mean that net metering provides an inefficient incentive to adopt rooftop solar DG or other forms of DER. Prices that compensate DERs for exports to the grid or for load reductions equally in all hours and across all months may overestimate the distribution cost savings that these resources generate for Eversource's customers in some periods and underestimating in others.

New pricing mechanisms for DERs may be required as alternatives to net metering to provide cost-reflective compensation, one that better aligns with the incremental benefits of these resources to the utility and society. Time-differentiated marginal costs associated with the upstream distribution grid provide useful information to evaluate and design DER pricing models, which should in principle be technology-neutral.

The MCOS study confirms that the bulk of Eversource's stations peak in similar hours, and these are fairly coincident with the system peak hour. Thus, the system-wide time-differentiation as developed in this MCOS study serves a reasonable basis upon which to inform setting time of use DER compensation in most locations of Eversource's service territory.[1] The potential distribution investment deferral value of DER technologies is location-specific. The MCOS provides an average marginal cost both system-wide and for capacity constrained areas as well as information on the regions that are expected to experience upstream capacity additions over the study period.

Table 1 below summarizes the marginal growth-related cost of bulk station and distribution substation, both as a system-wide and averaged for the capacity-constrained areas, and the corresponding annualized values, on a dollar per kW of peak load basis.

Table 1. Marginal Distribution Station Costs as System-Wide and in Capacity Constrained Areas

	System-Wide Marginal Cost		MCs in Capacity-Constrained Areas	
	Bulk Station (2019 $/kW-yr)	Dist. Substation (2019 $/kW-yr)	Bulk Station (Locational) (2019 $/kW-yr)	Dist. Substation (Locational) (2019 $/kW-yr)
Marginal Investment per kW of Peak Load	$112.46	$13.00	$341.11	$331.39
Annual Marginal Station Cost ($/kW-yr)	**$12.82**	**$1.49**	**$38.76**	**$37.98**

[1] The exceptions are a small share of bulk stations, representing less than 10 percent of the total load, which generally experience their highest loads in either December or January.

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

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.

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.[2]

The results of the MCOS study will be helpful to inform Eversource's distribution rate designs. Additionally, there is increased interest in the potential value of customer-sited distributed generation (DG), as well as other distributed energy resources (DERs) for the upstream distribution system. Developing the cost basis for compensation mechanisms to these emerging technologies requires a project specific analysis of the type that has been undertaken in this MCOS study.

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.

II. PRINCIPLES OF 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.

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

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 need. 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. Thus, decisions regarding class revenue requirement should take into account marginal cost information by class.

This principle is relevant not only for retail rate designs but also for DER pricing considerations. An important goal in the development of alternative prices for DERs is to ensure that these resources are connected to the utility system in the most efficient way possible. 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 without representing uneconomic bypass, which would increase the overall cost of service.

III. ELEMENTS OF EVERSOURCE'S MARGINAL DISTRIBUTION COSTS

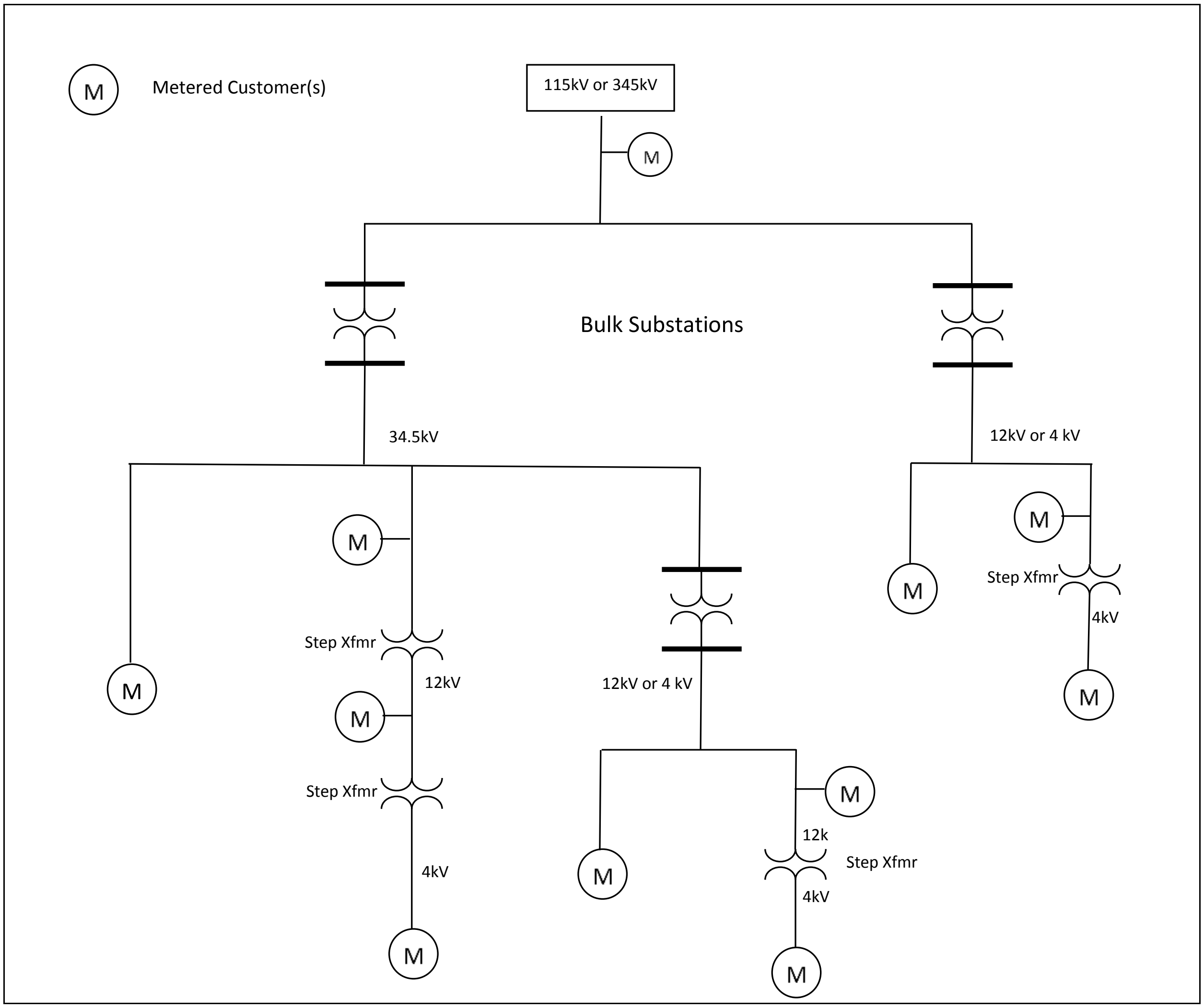
The NH system is varied and complex. The starting point for the MCOS study was identifying the various elements and voltage levels of the Company's distribution system. Eversource's primary voltage distribution system includes the following main elements:

- Bulk stations that are fed from the transmission system (115kV) and typically convert power to 34 kV or directly to 12 kV;
- Distribution 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 and 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. Finally, 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 marginal high voltage distribution costs per kW of 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



IV. UPSTREAM DISTRIBUTION MARGINAL COSTS

A. Investment

EI reviewed the current and expected station peak loading as well as existing nameplate rating and planned investments. Going forward, the Company does not foresee significant peak load growth on a system-wide basis. Eversource's load forecasts reflect that the 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. However, the majority of the bulk stations and substations are expected to be able to accommodate load growth without triggering a capacity addition over the upcoming five-year period.

The Company anticipates that station capacity expansion will be needed in a number of locations in order to meet the minimum planning criteria. The MCOS builds upon an in-depth review of the Company's budgeted investments for the upcoming planning period (2019 -2023). Our review identified specific bulk station and distribution substation expansion projects. EI reviewed the nature of these projects and identified the cost associated with capacity expansion in capital planning. These projects generally involve replacement of existing substation transformers with one (or two) larger transformers. These investments intend to address existing or expected overload conditions, serve new step industrial or commercial load additions, and/or offload nearby substations.

Projects associated with retirement of obsolete equipment were excluded from the MCOS analysis, since these are one-time investments and are unlikely to be impacted by changes in the 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).

The first step in EI's computation of marginal cost of bulk and distribution stations was to divide the identified planned investments by the project added capacity. In the case of bulk stations, converting the marginal investment per kW of capacity to a dollar per-kW of peak load required using a design-related adjustment factor. For bulk stations, Eversource distribution planners implicitly decide the timing of expansion of the station to ensure that each station is pre-loaded at no more than 75 percent of its normal (nameplate) rating, to avoid exceeding the station long term emergency rating.[3] On the other hand, marginal distribution substation marginal costs are not generally considered for an upgrade until their loads begin to reach their nameplate rating. Thus, no capacity adjustment factor was necessary in the case of marginal distribution substation costs.

Eversource, like many other distribution utilities, generally predicts the required investments in bulk stations and distribution stations 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 the execution of those projects are subject to further review by the Company as the date approaches, since the distribution area's load growth may or may not materialize as expected. In any case, the MCOS utilizes information from the full five-

[3] 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.

year capital plan period to compute marginal station costs as opposed to limiting the analysis to the first three years to provide a longer-term view of marginal distribution station costs.

B. 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 (2014-2017) and divided the annual expenses by the kW of non-coincident peak demand at bulk stations and distribution substations. 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 load growth.

C. System-wide versus Locational Cost Estimates

Eversource's standard distribution rates do not vary by geographical location, therefore, EI applied an adjustment factor to the marginal distribution costs estimated for the capacity-constrained areas of the service territory to compute a system-wide marginal cost. This adjustment factor represents the peak-load share of the bulk and distribution stations that are likely to require capacity investments, based on whether they will fall short of meeting the planning design criteria throughout the five-year period.

Because of the higher uncertainty of station peak load growth beyond the three-year timeframe, a number of 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 bulk 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 some of the high-growth distribution areas will have ample station capacity to serve peak loads during the study period. A zero marginal cost is implicitly assumed for these areas.

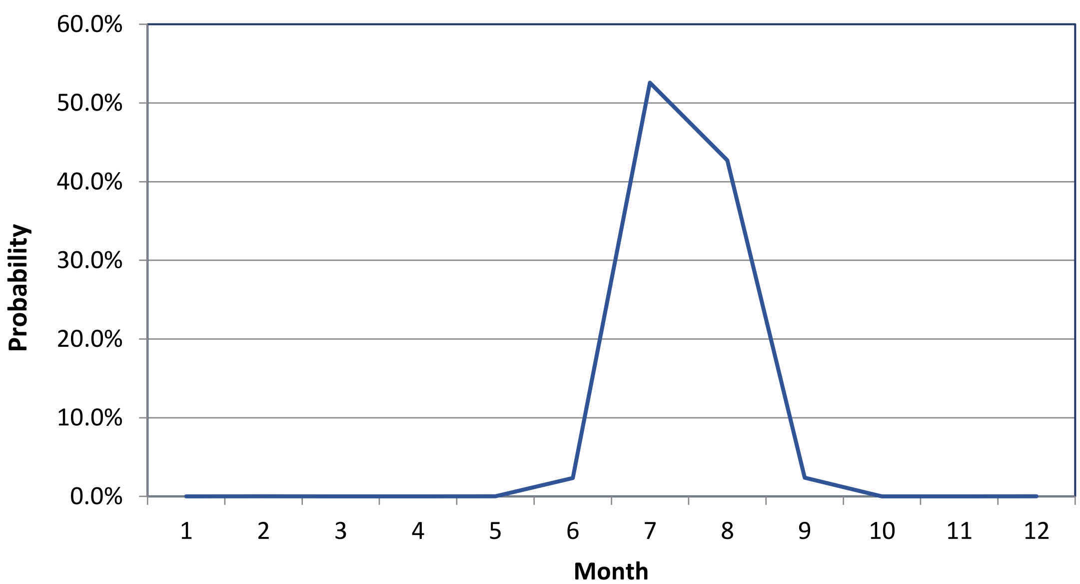
Finally, the marginal distribution substation cost was further adjusted to recognize that the majority of Eversource's overall load (about 83 percent) does not make use of distribution substations. The bulk station and distribution substation marginal costs were then annualized, both for the capacity-expansion areas and as a system-wide average marginal cost estimate, using marginal O&M expenses, and loading factors. The annualization process is explained in Appendix 1.

D. Time-differentiation

The annualized marginal bulk station and marginal distribution costs must be allocated to those hours in the year where load growth (or load reduction) is more likely to have an impact on the planned investment decisions. The analysis requires looking at the sum of distribution non-coincident peaks, which may not be coincident with the transmission system peak. Transmission loads not related to Eversource's retail loads may influence the timing of the overall transmission system peak in New Hampshire. EI undertook a Probability of Peak (POP) analysis using the combined hourly load shapes of the entire set of Eversource's bulk substations during the three most recent years (2015 through 2017) to account for weather variability and other factors that may affect the annual distribution station peak hour. This analysis informs the required time of day periods and seasons.

Our analysis showed that loads in the summer months of July and August are clearly driving the upstream distribution capacity expansion investments. Only a small number of bulk substations, representing about 9 percent of the total load, peak in the winter months of December or January. The POP analysis produced 864 hourly probabilities, for each typical weekday and weekend by month. The MCOS uses the hourly POP factors to allocate bulk station and distribution substation marginal annual costs to hours and months. Figure 2 below illustrates these findings. The months of July and August account for 95.3 percent of the system-wide annual probability of distribution peak. The remaining 4.7 percent falls in the months of September and June.

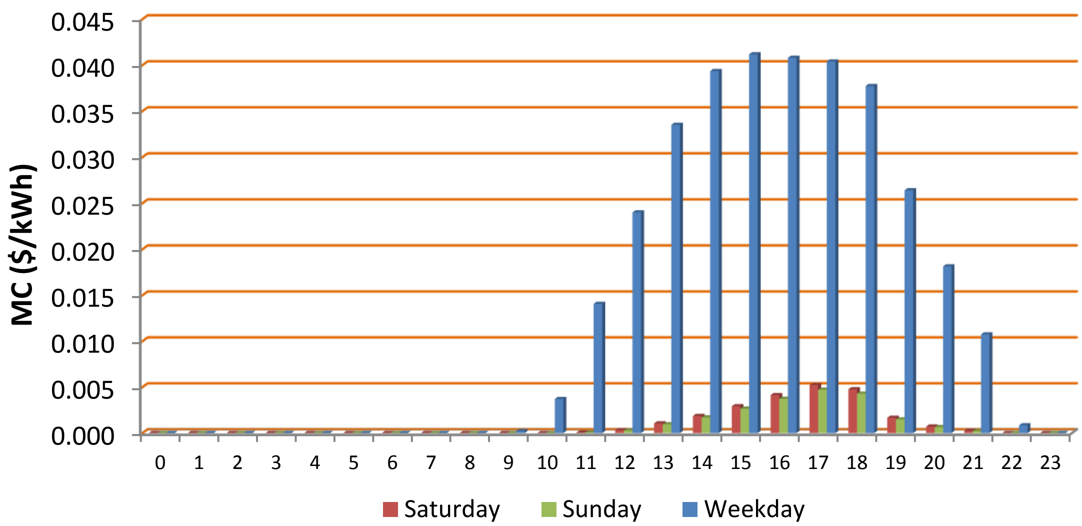
Figure 2. System-Wide Probability of Distribution Peak by Month



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.

Figure 3 illustrates the hourly pattern of estimated system-wide total marginal bulk station and the distribution substation costs, adjusted to include primary and secondary services in July and August. Hourly costs have been adjusted by primary and secondary losses. Hours noon to 8 pm of weekdays exhibit the highest hourly distribution costs.

Figure 3. Hourly Marginal Bulk Station and Distribution Substation Costs Averaged for the two Peak Summer Months (July & August)



As a result, 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, noon to 8 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, Option B. This option was intended to test the resulting average marginal costs in the event that the Company considered a more gradual move 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 2 and 3 below summarize the two alternative costing periods.

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

Seasons		**Time of Use Hours**
Summer (July - August)	*Peak:*	Mo - Fri: Noon to 8:00 pm; except Holidays
	Off-Peak:	Mo - Fri: 8:00 pm to Noon; Weekends and Holidays: All hours
Winter (Jan – June & Sep-Dec)	*No TOD*	All hours

Table 3. Alternative Time of Day and Seasonal Periods (Option B)

Seasons		**Time of Use Hours**
Summer (June - Sep)	*Peak:*	Mo - Fri: Noon to 8:00 pm; except Holidays
	Off-Peak:	Mo - Fri: 8:00 pm to Noon; Weekends and Holidays: All hours
Winter (Jan – May & Oct – Dec)	*No TOD*	All hours

V. LOCAL DISTRIBUTION FACILITIES

A. Investment

The Company's distribution facilities that are closer to the customers are less extensively shared and this has an impact on how they are designed within the Company's planning process and what the cost drivers are. These facilities may include primary taps, line transformers and secondary lines. The service drop generally serves a single customer and therefore the MCOS considers it part of the marginal customer related cost, along with the installed cost of the meter and associated equipment such as current transformer.

EI 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 incurred based on the connected customers' "design demands", as opposed to ongoing changes in their demand from month to month or even year to year. 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.[4]

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. To estimate the typical installed cost of distribution facilities, Eversource provided an extensive sample of work orders associated with customer connection jobs in the most recent three years (2015-2017). The sample was considered 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 account per jobs for each service classification. EI reviewed the work orders, and computed the average cost of distribution facilities, after customer contributions as per the line extension policy, on a per kW of design demand basis. This cost information was separately computed for each service class.

To estimate design demands by rate class, the MCOS relied on information conducted by Eversource on the average number of customers that are typically connected to a transformer, differentiating by residential versus general service, and single versus three-phase customers.[5] EI divided the average transformer size by rate class by the typical number of customers served from a transformer for each customer type.

EI estimated the average local facility cost by customer class, excluding customer contributions as per Eversource's line extension policy. Customers with underground facilities are generally required to pay for the costs that exceed that of an equivalent overheard facility. 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 given that there was not a forecast of O&M expenses. The average of 2015 -2017 O&M facilities expense per

[4] An example is when a residential building is removed and replaced by a business with intensive electricity use.

[5] The cost of distribution facilities for customers on the LG and GV rates was not included since these customers are responsible to provide their own transformer, or pay for use of the Company's transformer outside of rates.

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 2015-2017 and installed cost of the fixtures expected to be used by street lights going forward.

VI. MARGINAL CUSTOMER COSTS

A. Meter and Service Costs

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.[6]

The second customer-related cost component is the service drop. EI estimated the annualized installed cost of the service drop (after customer contributions) for all customer categories, based on a review of work orders over the most recent three years (2015-2017) involving single phase and three phase customers. An average installed cost per customer service drop was computed separately for single phase and three phase, as well as by overhead vs. underground. EI estimated the weighted average of the underground and overhead costs of service based on the breakdown of customers currently using each type of service 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. As a starting point, we relied on expense allocation factors developed by Eversource for each class. EI reviewed the trend in per-customer expense in recent years, stated in constant dollars, using FERC Form 1 accounts for the period 2014-2017 and after considering the observed declining trend in these expenses, the average expense per customer in 2016 and 2017 was used as an estimate of future marginal expense of these set of accounts. The same approach was used to estimate marginal customer service and informational expenses.

[6] The meter cost does not include separate instrument transformer costs for general service rate customers, since the typical cost by rate class was not available.

VII. SUMMARY OF MARGINAL COSTS

Table 4 shows system-wide marginal distribution bulk station and distribution station costs stated on a per-kW-month basis. The results are shown by peak/off-peak periods using three alternatives, i.e., the current TOU periods (7:00 am to 8:00 pm), the proposed peak period (noon-8 pm) and the summer and non-summer seasonal definitions as per Option A and Option B. Seasonal average marginal costs are also shown for the sake of comparison with the annual average marginal cost. Table 5 shows the marginal costs stated on a per-kWh basis.

Table 4. Annual and Time-differentiated System-Wide Marginal Station Costs per kW at Primary and Secondary Service Voltage ($ per kW-month)

	Total Marginal Cost Bulk + Dist. Subs
	At Secondary Service (2019 $ per kW-mo)
No Seasonality	
Peak	$1.11
Off-Peak	$0.14
Monthly Average	$1.25
Annual Average	$1.25
Option A	
Winter, All hours	$0.07
Summer, Peak	$6.20
Summer, Off-Peak	$0.96
Average winter	**$0.07**
Average, summer	**$7.16**
Option B	
Winter, All hours	$0.00
Summer, Peak	$3.27
Summer, Off-Peak	$0.49
Average winter	**$0.00**
Average, summer	**$3.76**

Table 5. Annual and Time-differentiated System-Wide Marginal Station Costs per kWh at Primary and Secondary Service Voltage ($ per kWh)

	Total Marginal Cost Bulk + Dist. Subs
	At Secondary Service (2019 $ per kWh)
No Seasonality	
Peak	$0.00411
Off-Peak	$0.00031
Monthly Average	$0.00172
Annual Average	$0.00172
Option A	
Winter, All hours	$0.00010
Summer, Peak	$0.04160
Summer, Off-Peak	$0.00166
Average winter	**$0.00010**
Average summer	**$0.00979**
Option B	
Winter, All hours	$0.00000
Summer, Peak	$0.02194
Summer, Off-Peak	$0.00084
Average winter	**$0.00000**
Average summer	**$0.00514**

Table 6 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 7 summarizes the monthly marginal customer-related costs by rate class.

Table 6: Summary of Monthly Marginal Local Distribution Facilities Costs by Rate Class

Customer Class	Monthly (After CIAC) Distribution Facilities Cost per kW of Design Demand	Average Customer Design Demand
	(2019 $/kW/mo)	(kW)
Residential Power & Light	$1.48	11.6
Residential OTOD	$1.48	11.6
General Service Power & Light 1 Phase	$1.30	19.5
General Service Power & Light 3 Phase	$1.89	26.3
General Service OTOD 1 Phase	$1.30	19.5
General Service OTOD 3 Phase	$1.89	26.3

Table 7. Summary of Monthly Marginal Customer Costs by Rate Class

Customer Class		Monthly Marginal Customer Cost
		($/Cust/mo.)
R-P&L	Residential Power & Light	$16.12
R-OTOD	Residential OTOD	$17.76
R-C-WH	Residential Controlled WH	$9.25
R-LCS	Residential LCS	$9.25
R-UC-WH	Residential Uncontrolled WH	$9.25
GS-P&L-P1	General Service Power & Light 1 Phase	$18.21
GS-P&L-P3	General Service Power & Light 3 Phase	$34.21
GS-OTOD-P1	General Service OTOD 1 Phase	$21.87
GS-OTOD-P3	General Service OTOD 3 Phase	$42.72
GS-UC-WH	General Service Uncontrolled WH	$9.25
GS-C-WH	General Service Controlled WH	$9.25
GS-LCS-P1	General Service LCS 1 Phase	$9.25
GS-LCS-P3	General Service LCS 3 Phase	$25.24
GS-SH	General Service Space Heating	$14.79
GV	Rate GV	$254.21
LG	Rate LG	$2,958.59
Resale	Resale	$86.26

VIII. KEY IMPLICATIONS OF MARGINAL COST RESULTS FOR PRICING DECISIONS

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.[7] 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 upstream and distribution substation costs (the per-kWh charges may also be replaced with time-differentiated metered per-kW charges).
- A monthly fixed customer charge that recovers any 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 kW of design demand that recovers the marginal costs of local distribution facilities (local primary lines, transformers, secondary lines).

The specific form of the facilities charge may vary depending on the type of customers served from the transformer and how homogeneous their loads are, such as whether they are all-electric customers or they use both electricity and gas. The facility charge will be levied on an estimate of the customer's design demand that reflects the per-kW customer monthly maximum demand that the customer is not expected to exceed. 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 local customers, and the less diversified loads since they typically serve a few customers.[8] 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 peak kW size within the rate class.

[7] Consumption levels that would exist under marginal cost price signals.

[8] When a customer lowers its monthly maximum demand below the assumed design standard, the transformer capacity that is freed up is not generally needed to serve the loads of other customers connected to the same transformer unless in exceptional circumstances.

B. Marginal Cost Use for DER Value and Net Metering Evaluation

Time-differentiated marginal costs associated with the upstream distribution grid provide useful information to evaluate and design DER pricing models, which should in principle be technology-neutral. Ultimately, DER prices will aim to ensure that these resources are integrated into the utility system in the most efficient way so as to avoid a higher overall cost of providing reliable service and therefore higher rates for non-DER customers. New pricing mechanisms for DERs may be required as alternatives to net metering to provide cost-reflective compensation, one that better aligns with the incremental benefits of these resources to the utility and society. This also requires ensuring that compensation reflects the net incremental value of DERs to the system over the upcoming utility's planning period after considering any potential added costs associated with handling two-way power flows.

At the distribution level, the starting point to achieve these goals require that kWh and/or kW distribution prices be time-differentiated and reflect as close as possible the marginal cost associated with the output of the DER. Such prices are informed using a time-differentiated marginal cost analysis of the type that has been undertaken in this study. Time-differentiated prices that reflect the marginal costs associated with the upstream distribution grid provide useful information to the design of DER compensatory pricing models. In the case of Eversource, our analysis demonstrated that the majority of bulk stations tend to peak in the same summer hours. Thus, the system-wide time-differentiation results obtained in this MCOS study provide a reasonable basis upon which to inform setting time of use DER compensation in most locations of the service territory.[9]

A second important finding of our study relevant to the net metering discussion is that marginal distribution costs per kW of peak load are substantially lower than the current per-kWh charges in Eversource's NH distribution rates. As a result, net metering may encourage an inefficient adoption of rooftop solar DG under current rates. Marginal cost estimates are useful to quantify the potential cross-subsidies that may take place, i.e., the difference between DER customer's bill credits and the utility's avoided distribution grid costs. The gap may result in higher rates for non-net metering customers at the time of the next rate case.

Any DER pricing structure that may be considered as an alternative to net metering, such as the explicit compensation of exports or a "buy-all, sell-all" approach that prices separately the customer's full usage and their DER output should reflect more detailed marginal cost information (e.g., time-differentiated) and ideally considers the impact on the local grid. Station investments are only truly avoidable if the utility can count on the output from such facilities

[9] The exceptions are a small share of bulk stations, representing less than 10 percent of the total load, which generally experience their highest loads in either December or January.

during the peak hours in the specific distribution area. To the extent that the Company will continue to expand upstream distribution costs to provide service to the DG or DER owner, their rates will need to recover those costs in a manner comparable to non-DER customers. In addition, as discussed in this report, the cost driver for transformers and local lines is the customer's long-term design demand. Thus, in most cases, the same amount of local transformer capacity may be required to serve a customer with such facilities.

C. Marginal Costs as Per Current Rate Structures

In order to evaluate the efficiency in the existing distribution price signals, it is useful to compare them with marginal unit costs. Table 8 summarizes the marginal cost results following the structure of Eversource's existing distribution rates, i.e., using the same rate components as TOU periods as in current TOD rates. Table 8 shows two alternatives to present the marginal distribution bulk station and substation cost. One method uses a per-kW-month basis, the other a per-kWh cost. We note that the marginal cost-based charges strictly reflect marginal costs with no reconciliation for revenue targets. Adjustments to the components would be necessary to capture the allocated embedded or "sunk" costs to each class. This would first require a computation of class marginal cost revenues to determine the marginal cost revenue shortfall.[10]

Currently, the bulk of the residential customers pay flat (non-time differentiated) distribution rates, therefore Table 8 uses an annual average of the marginal cost to enable the comparison with those rates. 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 as a fixed per-customer charge since these costs do not change with kWh usage or near-term changes in peak load. Tables 9 and 10 reflect the marginal cost information for the residential and general service TOD rates, using more cost reflective periods and seasons defined as per Options A and B.

[10] Estimating the class' marginal cost revenues requires multiplying the hourly marginal distribution costs, marginal distribution facilities costs and marginal customer costs by the class' billing determinants.

Table 8. Marginal Costs over 2019-2023 stated as per Current Distribution Rate Structures

		Alternatives for Recovery of Local Distribution Facilities (after CIAC) MCOS		Alternatives for Recovery of Bulk and Dist. Substation MC		
	Customer-related MC	Fixed per Customer	Or: Per-kW of Customer Design Demand	TOU Period	Per-Metered Demand (kW)	Or: Per-kWh
Rate Class	($/Cust./mo)	($/Cust./mo)	($/kW)		($/kW-mo)	($/kWh)
R-P&L	16.12	17.24	1.48	All	1.25	0.00172
R-OTOD	17.76	17.24	1.48	On-Peak Off-Peak	1.11 0.14	0.00411 0.00031
R-C-WH	9.25	-	1.48	All	1.25	0.00172
R-LCS	9.25	-	1.48	All	1.25	0.00172
R-UC-WH	9.25	-	1.48	All	1.25	0.00172
GS-P&L-P1	18.21	25.39	1.30	All	1.25	0.00172
GS-P&L-P3	34.21	49.82	1.48	All	1.25	0.00172
GS-OTOD-P1	21.87	25.39	1.48	On-Peak Off-Peak	1.11 0.14	0.00411 0.00031
GS-OTOD-P3	42.72	49.82	1.48	On-Peak Off-Peak	1.11 0.14	0.00411 0.00031
GS-UC-WH	9.25	-	1.30	All	1.25	0.00172
GS-C-WH	9.25	-	1.30	All	1.25	0.00172
GS-LCS-P1	9.25	-	1.30	All	1.25	0.00172
GS-LCS-P3	25.24	-	1.89	All	1.25	0.00172
GS-SH	14.79	-	1.30	All	1.25	0.00172
GV	254.21	na	na	All	1.25	0.00172
LG	2,958.59	na	na		1.25	0.00171
Streetlighting	($/fixture/mo.)					
OL	6.07	na	na			
EOL	6.07	na	na			

Table 9. Marginal Station Costs Using Option A TOD Periods

Service Classification	Months	TOD	Alternatives for Bulk Station & Distribution Station MC - OPTION A TOU: Demand charge ($/kW-mo)	Or: Per-kWh charge ($/kWh)
R-OTOD & GS-OTOD-P1	Jul - Aug	On-Peak	6.20	0.04160
		Off-Peak	0.96	0.00166
	Sep - Jun	All hours	0.06	0.00010

Table 10. Marginal Station Costs Using Option B TOD Periods

Service Classification	Time-Differentiation, Option B: Months	TOD	Alternatives for Upstream & Distribution Station MC - OPTION B: Demand charge ($/kW-mo)	Or: Per-kWh charge ($/kWh)
R-OTOD & GS-OTOD-P1	Jun - Sep	On-Peak	3.27	0.02194
		Off-Peak	0.49	0.00084
	Oct - May	All hours	0.00	0.00000

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, and adjusting the investment per unit by the general plant loading factor and a plant-related A&G loading factor. To these costs, EI added marginal O&M expenses, non-plant related A&G expenses, and revenue requirements for working capital to obtain the annualized marginal costs. A summary of the calculation of these components is provided below.

Loaders

All marginal investment and marginal O&M expenses were adjusted by the corresponding loading factor. Loaders include plant-related A&G, non-plant-related A&G and general plant loading factors. These are required to capture the additional plant or O&M expenses, or overhead costs incurred when electric plant or electric O&M expense increase. Certain administrative and general (A&G) expenses can grow either with plant or with O&M expenses. Accounts not marginal with respect to other expenses or plant must be excluded.[11] The MCOS estimated a non-plant-related A&G loader based on the average ratio of non-plant-related A&G expenses (FERC Accounts 926 and 408.1) to O&M expenses over the period 2003-2017, or 4.87%.

For the plant-related A&G expense loading factor, the MCOS used the two A&G FERC accounts that clearly vary with the amount of plant in service: Maintenance of General Plant (FERC Account 935) and Property Insurance (FERC Account 924). EI did not find a positive correlation between any of these accounts with regard to cumulative net additions to total electric plant, due largely to several corporate and structural changes that the Company has experienced in recent years. We estimated plant-related A&G using property and terrorism insurance rate per 100 dollars of investment. This plant-related A&G loader is only applicable to bulk station and distribution substation marginal costs.

[11] The MCOS excluded FERC Accounts 922 Administrative Expenses Transferred (Credit), 923 Outside Services Employed, 927 Franchise Requirements, 928 Regulatory Requirements, 930.1 Institutional and Goodwill Advertising Expenses, and 931 Rents.

Finally, EI estimated a loading factor associated with changes in General Plant as distribution plant grows. General plant consists of items such as office buildings, warehouses, cars, trucks and other equipment. The MCOS estimated a General Plant loader equal to 6.970%, based on a regression of 15 years of cumulative net additions to general plant on cumulative net additions to total plant less general plant additions.

Economic Carrying Charges

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). An economic carrying charge represents the market or "rental" value of a unit of capacity, and unlike levelized charges, rises at the rate of inflation. The present value of this stream of revenues is equal to the present value of the costs (revenue requirements) associated with owning the asset. The ECC uses a formula that essentially calculates the cost of shifting investment forward by one year in order to serve an increment of load this year. The ECC is such that it compensates the investor for the costs of moving the investment forward in time. The economic carrying charge for subsequent years is simply the first-year charge adjusted by inflation.

EI used the elements of Eversource's revenue requirement associated with incremental plant for the ECC calculation. These include: the utility's incremental cost of capital (mix of debt and equity, and their respective long-term costs), the expected inflation rate for that type of plant, net of technical progress, and the average service life and patterns of failure ("Iowa curve") for each type of plant. Eversource foresees financing of incremental investment through sales of common stock (53.50%) and debt (46.50%). The long-term incremental cost of debt is expected to be 5% over the planning period and the incremental cost of common stock is 10.50%. The ECC calculation used a long-term inflation assumption of 2%.

Working capital requirements

We used a factor in the MCOS that allows including working capital requirements, including components for cash, materials, supplies and prepayments. The revenue requirement for this working capital was developed from Eversource's weighted average cost of capital plus an income tax component that recognizes that the equity portion of return on capital is taxable.

Annualization Tables

Table A.1.1. below shows the derivation of annualized costs both on a system-wide basis and on a more locational basis, for customers located in the areas that will be experiencing capacity additions to accommodate load growth.

Table A.1.1 Annualized Marginal Bulk-Station and Distribution Substation Costs stated as System-wide Average and as an Average in Capacity-Constrained Areas

	System-Wide Marginal Cost		MCs in Capacity-Constrained Areas	
	Bulk Station	Dist. Substation	Bulk Station (Locational)	Dist. Substation (Locational)
	(2019 $/kW-yr)	(2019 $/kW-yr)	(2019 $/kW-yr)	(2019 $/kW-yr)
Marginal Investment per kW of Peak Load	$112.46	$13.00	$341.11	$331.39
With General Plant Loading x 1.0697	120.30	13.91	364.88	354.49
Annual Economic Carrying Charge	8.43%	8.43%	8.43%	8.43%
A&G Loading (plant related)	0.02%	0.02%	0.02%	0.02%
Total Annual Carrying Charge	8.45%	8.45%	8.45%	8.45%
Annualized Capital Costs	10.16	1.18	30.83	29.95
Annual O&M Expenses	$2.29	$0.27	$6.84	$6.95
With A&G Loading x 1.0487 (Non-plant Related	2.41	0.29	7.17	7.29
Subtotal	12.57	1.46	38.00	37.24
Working Capital				
Material and Supplies	1.37	0.16	4.14	4.02
Prepayments	0.82	0.09	2.48	2.41
Cash Working Capital Allowance	0.30	0.04	0.90	0.91
Total Working Capital	2.48	0.29	7.52	7.35
Revenue Requirement for Working Capital	0.25	0.03	0.76	0.74
Annual Marginal Station Cost ($/kW-yr)	**$12.82**	**$1.49**	**$38.76**	**$37.98**

Table A.1.2 Annualized Marginal Distribution Facilities Costs Net of Customer Contributions

	R-P&L	R-OTOD	GS-P&L-P1	GS-P&L-P3	GS-OTOD-P1	GS-OTOD-P3	GS-SH
	Residential Power & Light	Residential OTOD	General Service Power & Light 1 Phase	General Service Power & Light 3 Phase	General Service OTOD 1 Phase	General Service OTOD 3 Phase	General Service Space Heating
	----------------- (2019 Dollars per kW of Design Demand) -----------------						
Marginal Investment per kW of Design Demand	$118.24	$118.24	$118.24	$189.85	$118.24	$189.85	$118.24
With General Plant Loading x 1.0697	$126.48	$126.48	$126.48	$203.08	$126.48	$203.08	$126.48
Annual Economic Carrying Charge Related to Capital Investment	9.09%	9.09%	9.09%	9.09%	9.09%	9.09%	9.09%
Annualized Costs	$11.50	$11.50	$11.50	$18.46	$11.50	$18.46	$11.50
Annual Expense per kW of Design Demand	5.70	5.70	3.66	3.66	3.66	3.66	3.66
With A&G Loading x 1.0487	5.97	5.97	3.84	3.84	3.84	3.84	3.84
Distribution Facilities Related Costs	$17.47	$17.47	$15.33	$22.30	$15.33	$22.30	$15.33
Working Capital							
Material and Supplies	1.44	1.44	1.44	2.30	1.44	2.30	1.44
Prepayments	0.86	0.86	0.86	1.38	0.86	1.38	0.86
Cash Working Capital Allowance	0.75	0.75	0.48	0.48	0.48	0.48	0.48
Total Working Capital	$3.04	$3.04	$2.78	$4.17	$2.78	$4.17	$2.78
Revenue Requirement for Working Capital	0.31	0.31	0.28	0.42	0.28	0.42	0.28
Total Annualized Marginal Distribution Facilities Cost per kW of Design Demand ($/kW-yr)	**$17.78**	**$17.78**	**$15.61**	**$22.72**	**$15.61**	**$22.72**	**$15.61**

Table A.1.3. Annualized Street-Lighting Marginal Costs

	50 W	75 W	100 W	150 W	250 W	400 W
	(2019 Dollars per fixture)					
Marginal Investment per fixture	$559.10	$545.78	$553.53	$549.73	$608.72	$612.03
With General Plant Loading x 1.0697	$598.07	$583.82	$592.11	$588.05	$651.15	$654.69
Annual Economic Carrying Charge Related to Capital Investment	11.10%	11.10%	11.10%	11.10%	11.10%	11.10%
Annualized Costs	$66.40	$64.82	$65.74	$65.29	$72.29	$72.69
Lighting O&M Expenses	$4.35	$4.35	$4.35	$4.35	$4.35	$4.35
With A&G Loading x 1.0487 (non-plant related)	$4.57	$4.57	$4.57	$4.57	$4.57	$4.57
Distribution Facilities Related Costs	$70.97	$69.39	$70.31	$69.86	$76.86	$77.25
Working Capital						
Material and Supplies	$6.79	$6.63	$6.72	$6.67	$7.39	$7.43
Prepayments	$4.07	$3.97	$4.03	$4.00	$4.43	$4.45
Cash Working Capital Allowance	$0.57	$0.57	$0.57	$0.57	$0.57	$0.57
Total Working Capital	$11.43	$11.17	$11.32	$11.24	$12.39	$12.45
Revenue Requirement for Working Capital	$1.15	$1.12	$1.14	$1.13	$1.25	$1.25
Total Annual Marginal Per Light Cost	**$72.12**	**$70.51**	**$71.44**	**$70.99**	**$78.11**	**$78.51**

Table A.1.4 Annualized Customer-Related Marginal Costs (Residential and GS Rates)

	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
				---------------- (2019 Dollars per Customer) ----------------					
Meter Investment	$57.35	$152.35	$57.35	$57.35	$57.35	$57.35	$269.69	$269.69	$764.07
With General Plant Loading (1) x 1.0697	$61.34	$162.96	$61.34	$61.34	$61.34	$61.34	$288.49	$288.49	$817.33
Annual ECC related to Capital Investment	9.37%	9.37%	9.37%	9.37%	9.37%	9.37%	9.37%	9.37%	9.37%
Annualized Meter Costs	$5.75	$15.27	$5.75	$5.75	$5.75	$5.75	$27.03	$27.03	$76.57
Service Cost	$1,019.15	$1,019.15	$1,019.15	$1,019.15	$1,019.15	$1,019.15	$2,541.28	$1,019.15	$2,541.28
With General Plant Loading x 1.0697	$1,090.18	$1,090.18	$1,090.18	$1,090.18	$1,090.18	$1,090.18	$2,718.40	$1,090.18	$2,718.40
Annual ECC related to Capital Investment	9.09%	9.09%	9.09%	9.09%	9.09%	9.09%	9.09%	9.09%	9.09%
Annualized Service Drop Costs	99.12	99.12	99.12	99.12	99.12	99.12	247.15	99.12	247.15
Meter O&M Expenses	$5.64	$14.99	$5.64	$5.64	$5.64	$5.64	$26.53	$26.53	$75.17
Customer Accounts Expenses	$57.70	$57.70	$0.00	$0.00	$0.00	$81.40	$81.40	$81.40	$81.40
Customer Service & Informational Expenses	$19.99	$19.99	$0.00	$0.00	$0.00	$19.94	$19.94	$19.94	$19.94
With A&G Loading x 1.0487 (Non-plant Related)	$87.38	$97.18	$5.92	$5.92	$5.92	$112.19	$134.09	$134.09	$185.10
Sub-total Annualized Cost of Meter, Service and Customer Expenses	$192.24	$211.56	$110.78	$110.78	$110.78	$217.05	$408.27	$260.23	$508.81
Revenue Requirement for Working Capital	$1.21	$1.52	$0.19	$0.19	$0.19	$1.52	$2.21	$2.21	$3.82
Total Annual Customer-Related Costs incl. Working Capital	**$193.45**	**$213.08**	**$110.96**	**$110.96**	**$110.96**	**$218.57**	**$410.48**	**$262.44**	**$512.63**

Table A.1.5 Annualized Customer-Related Marginal Costs (GS Riders and Street Lighting)

	GS-UC-WH	GS-C-WH	GS-LCS-P1	GS-LCS-P3	GS-SH	OL	EOL
	GS Uncont. WH	GS Controlled WH	GS LCS 1 Phase	GS LCS 3 Phase	GS Space Heating	Rate OL	Rate EOL
	----------------- (2019 Dollars per Customer) -----------------						
Meter Investment	$57.35	$57.35	$57.35	$269.69	$169.96	n/a	n/a
With General Plant Loading (1) x 1.0697	$61.35	$61.34	$61.34	$288.49	$181.81	n/a	n/a
Annual ECC related to Capital Investment	9.37%	9.37%	9.37%	9.37%	9.37%	n/a	n/a
Annualized Meter Costs	$5.75	$5.75	$5.75	$27.03	$17.03	n/a	n/a
Service Cost	$1,019.15	$1,019.15	$1,019.15	$2,541.28	$1,463.34	22.41	22.41
With General Plant Loading x 1.0697	$1,090.18	$1,090.18	$1,090.18	$2,718.40	$1,565.33	$23.98	$23.97
Annual ECC related to Capital Investment	9.09%	9.09%	9.09%	9.09%	9.09%	9.09%	9.09%
Annualized Service Drop Costs	99.12	99.12	99.12	247.15	142.31	2.18	2.18
Meter O&M Expenses	$5.64	$5.64	$5.64	$26.53	$16.72	$0.00	$0.00
Customer Accounts Expenses	$0.00	$0.00	$0.00	$0.00	$0.00	$9.43	$7.26
Customer Service & Informational Expenses	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
With A&G Loading x 1.0487 (Non-plant Related)	$5.92	$5.92	$5.92	$27.82	$17.53	$9.89	$7.61
Sub-total Annualized Cost of Meter, Service and Customer Expenses	$110.78	$110.78	$110.78	$301.99	$176.88	$12.07	$9.79
Revenue Requirement for Working Capital	$0.19	$0.19	$0.19	$0.88	$0.55	$0.12	$0.10
Total Annual Customer-Related Costs incl. Working Capital	**$110.96**	**$110.96**	**$110.96**	**$302.87**	**$177.43**	**$12.19**	**$9.89**

Table A.1.5 Annualized Customer-Related Marginal Costs (GV and LG and Sales for Resale)

	Rate GV	Rate LG	Resale
Meter Investment	$660.98	$660.98	$5,010.00
With General Plant Loading (1) x 1.0697	$707.05	$707.05	$5,359.20
Annual ECC related to Capital Investment	9.37%	9.37%	9.37%
Annualized Meter Costs (2) x (5)	$66.24	$66.24	$502.05
Meter O&M Expenses	$65.02	$65.02	$492.86
Customer Accounts Expenses	$260.98	$178.76	$0.00
Customer Service & Informational Expenses	$2,483.14	$33,126.95	$0.00
With A&G Loading x 1.0487 (Non-plant Related)	$2,945.95	$34,995.89	$516.86
Sub-total Annualized Cost of Meter, Service and Customer Expenses	$3,012.19	$35,062.13	$1,018.91
Revenue Requirement for Working Capital	$38.30	$440.93	$16.27
Total Annual Customer-Related Costs incl. Working Capital	**$3,050.48**	**$35,503.05**	**$1,035.18**

APPENDIX 2: MCOS BACK-UP TABLES

Table A.2.1 Derivation of Marginal Investment

	Upstream Bulk Station	Distribution Substation
Marginal Station Investment per kW of Added Project Capacity in growth areas, 2019-2023 (2019$ /kW)	$256.47	$331.39
Station Nameplate Rating Percent Margin over Station Load	33.0%	-
Marginal investment per kW of Station Peak in capacity constrained areas, 2019 - 2023 period, $/kW	$341.11	$331.39
Share of total system load that uses station type	98.28%	16.67%
Share of total peak load served from stations in areas with expected capacity expansion (2019-2023)	33.55%	23.54%
System-Wide Marginal Station Investment (2019 $ /kW)	**$112.46**	**$13.00**

Table A.2.2 Peak-Load Share of Bulk Stations in Capacity-Constrained Areas By Region

Region	2023 Estimated Peak Load in Constrained Areas	% of Total Peak Load in Constrained Areas	Region's Share of Total System Load Share
Central	319.2	39.5%	31.0%
Southern	143.0	18.0%	24.9%
Eastern	206.2	25.5%	21.2%
Northern	60.4	7.5%	14.9%
Western	79.2	9.8%	8.0%
Total	**808.0**	**100.0%**	**100%**

Total 2023 Bulk Station NCP Load (MW)	2,409

Peak Load Share of Total Bulk Station Peak Load: 33.05%

Table A.2.3 Peak-Load Share of Distribution Substations in Capacity-Constrained Areas by Region

Region	Peak Load in Constrained Areas (MW)	Distribution Substation Peak Load in Constrained Areas	Region's Share of Total System Load Share
Central	21.57	27%	31%
Southern	5.70	7%	25%
Eastern	29.41	36%	21%
Northern	13.63	17%	15%
Western	10.33	13%	8%
Total	**80.64**	**100%**	**100%**

Total 2023 Dis. Subs. NCP Load (MW)	342.60

Peak Load Share as percent of Total Peak Load: 23.54%

Table A.2.4 Marginal Investment in Bulk and Distribution Substation Station (2019-2023)

	2018	2019	2020	2021	2022	2023	Total (2019$)	Existing Capacity	New	Added	Inv/ Added Capacity	
								MW				
Growth-related Dis. Station Investment ($2019)	453.41	2,000.00	1,371.94	2,305.21	1,506.34	1,476.39	**9,113.29**	**16.5**	**44.0**	**27.5**	**331.4**	**$/kW**
Growth-related Bulk Station Investment ($2019)	783	4,000	9,800	11,046	18,829	18,455	**62,913**	**231.2**	**476.5**	**245.3**	**256.5**	**$/kW**

Table A.2.5 Marginal O&M Expenses of Bulk Station

		2014	2015	2016	2017	Average
(1)	Annual Bulk Station O&M Expenses (000 Dollars)	$13,332.37	$14,009.35	$14,191.31	$13,627.62	
(2)	Weather- normalized Bulk Station NCP (MW)	2,211	2,242	2,109	2,151	
(3)	O&M expense per kW of Bulk Station Peak Load	$6.03	$6.25	$6.73	$6.34	
(4)	Weighted Labor and Materials Cost Index (2019=1.00)	0.90	0.92	0.94	0.95	
(5)	Bulk Station O&M expense per kW of Peak Load (2019 Dollars)	$6.71	$6.77	$7.18	$6.69	
(6)	Marginal Station O&M Expense per kW of Peak Load in Areas of Growth over 2019-2023 (average of 2014-2017 expense) ($/kW-yr)					$6.84
(7)	Station Peak-load Share in areas of capacity expansion					33.55%
(8)	System-wide Marginal Bulk Station O&M Expense ($/kW-yr)					$2.29

Table A.2.6. Marginal O&M Expenses of Distribution Substation

		2014	2015	2016	2017	Average
(1)	Annual Distribution Subst. and Trunkline O&M Expenses (000 Dollars)	$2,063.05	$2,167.81	$2,195.96	$2,108.74	
(2)	Weather-normalized Dist. Subst. NCPs (MW)	337	341	321	327	
(3)	O&M expense per kW of Dis. Station Peak Load (2019 $/kW)	$6.13	$6.35	$6.84	$6.44	
(4)	Weighted Labor and Materials Cost Index (2019=1.00)	0.90	0.92	0.94	0.95	
(5)	Dis. Substation O&M expense per kW of Peak Load (2019 $/kW)	$6.82	$6.88	$7.30	$6.80	
(6)	Marginal Station O&M Expense per kW of Peak Load in Areas of Growth over 2019-2023 (average of 2014-2017 expense) ($/kW-yr)					$6.95
(7)	Station Peak-load Share in areas of capacity expansion					23.54%
(8)	System-wide Marginal Station O&M Expense ($/kW-yr)					$1.64
(9)	Share of the Company load served from a distribution substation					16.67%
(10)	System-wide Marginal Distribution Station O&M Expense ($/kW-yr)					$0.27
	System-wide Marginal Distribution Station O&M Expense ($/kW-yr)					$0.29

Table A.2.7 Marginal Investment in Distribution Facilities by Customer Class

Description	Facilities Cost per kW Of Design Demand ($/kW)
Residential Power & Light	$118.24
Residential OTOD	$118.24
General Service Power & Light 1 Phase	$118.24
General Service Power & Light 3 Phase	$189.95
General Service OTOD 1 Phase	$118.24
General Service OTOD 3 Phase	$189.95

Table A.2.8 Marginal Street Lighting Fixtures

	Investment per Fixture (2019 $)
50 W	559.10
75 W	545.78
100 W	553.53
150 W	549.73
250 W	608.72
400 W	612.03

Table A.2.9 Investment in 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.2.10 Investment in 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	
			$189.85				Weighted Average kVA (3-ph)	**$26.32**	**kVA**

Table A.2.11 Marginal O&M Expenses for Distribution Facilities

		Year				
		2014	2015	2016	2017	Average
(1)	Secondary Portion of Distribution Facility O&M Expenses (000's Dollars)	$11,537.7	$11,855.0	$13,428.2	$12,493.3	
(2)	Primary Portion of Distribution Facility O&M Expenses (000's Dollars)	$20,433.4	$22,314.3	$25,512.1	$23,268.0	
(3)	Design Demand on Secondary (MW)	6,552	6,543	6,604	6,674	
(4)	Design Demand on Primary (MW)	6,704	6,696	6,758	6,829	
(5)	Weighted Labor and Materials Cost Index (2019 = 1.00)	0.90	0.92	0.94	0.95	
(6)	Secondary Distribution Facilities O&M Expense Per kW of Design Demand (2019 Dollars/kW)	$1.96	$1.96	$2.17	$1.98	
(7)	Primary Distribution Facilities O&M Expense Per kW of Design Demand (2019 Dollars/kW)	$3.39	$3.61	$4.03	$3.60	
(8)	Annual Primary Distribution Facilities O&M Expense per kW for Primary Customer (Average 2014 - 2017)					**$3.66**
(9)	Total Annual Primary and Secondary Distribution Facilities O&M Expense per kW for Secondary Customer (Average 2014 - 2017)					**$5.70**

Table A.2.12 Installed Cost of Typical Meter and Number of Meters

Rate Description	Installed Meter Cost	Av. No. of Meters (2018)
Residential Power & Light	$57.3	438,114
Residential OTOD	$152.3	0
Residential Controlled WH	$57.3	39
Residential LCS	$57.3	0
Residential Uncontrolled WH	$57.3	252
General Service Power & Light - 1 Phase	$57.3	0
General Service Power & Light - 3 Phase	$269.7	3,641
General Service OTOD (1 Phase)	$269.7	0
General Service OTOD (3 Phase)	$764.1	42,913
General Service Uncontrolled WH	$57.4	0
General Service Controlled WH	$57.3	55,867
General Service LCS (1 Phase)	$57.3	0
General Service LCS (3 Phase)	$269.7	19,787
General Service Space Heating	$170.0	0
Rate GV	$661.0	15
Rate LG	$661.0	0
Resale	$5,010.0	198

Table A.2.13 Installed Typical Service Cost by Customer Class

Service Class	After CIAC Overhead Service Drop Investment	After CIAC Underground Service Investment	OH Service Share	UG Service Share	Average Service Cost Per Customer
	(2019 $ per customer)	(2019 $ per customer)	%	%	(2019 $ per customer)
R-P&L	969.08	1,207.51	79.0%	21.0%	**1,019.15**
R-OTOD	969.08	1,207.51	79.0%	21.0%	**1,019.15**
R-C-WH	969.08	1,207.51	79.0%	21.0%	**1,019.15**
R-LCS	969.08	1,207.51	79.0%	21.0%	**1,019.15**
R-UC-WH	969.08	1,207.51	79.0%	21.0%	**1,019.15**
GS-P&L-P1	969.08	1,207.51	79.0%	21.0%	**1,019.15**
GS-P&L-P3	1,531.34	4,120.92	61.0%	39.0%	**2,541.28**
GS-OTOD-P1	969.08	1,207.51	79.0%	21.0%	**1,019.15**
GS-OTOD-P3	1,531.34	4,120.92	61.0%	39.0%	**2,541.28**
GS-UC-WH	969.08	1,207.51	79.0%	21.0%	**1,019.15**
GS-C-WH	969.08	1,207.51	79.0%	21.0%	**1,019.15**
GS-LCS-P1	969.08	1,207.51	79.0%	21.0%	**1,019.15**
GS-LCS-P3	1,531.34	4,120.92	61.0%	39.0%	**2,541.28**
GS-SH	1,531.34	1,207.51	79.0%	21.0%	**1,463.34**

Table A.2.14 Meter O&M Expense by Customer Class

Class	Annual Meter Maintenance Expense Per Customer (2019 Dollars)
Residential Power & Light	$5.6
Residential OTOD	14.99
Residential Controlled WH	5.64
Residential LCS	5.64
Residential Uncontrolled WH	5.64
General Service Power & Light 1 Phase	5.64
General Service Power & Light 3 Phase	26.53
General Service OTOD 1 Phase	26.53
General Service OTOD 3 Phase	75.17
General Service Uncontrolled WH	5.64
General Service Controlled WH	5.64
General Service LCS 1 Phase	5.64
General Service LCS 3 Phase	26.53
General Service Space Heating	16.72
Rate GV	65.02
Rate LG	65.02
Resale	492.86

Table A.2.15 Annual Meter O&M Expense

Year	Total Meter O&M Expenses	Number of Metered Accounts	Weighted Number of Customers	Meter Expense Per Weighted Customer	Weighted Labor and Materials Cost Index	Meter Expense Per Weighted Customer
	(000's Dollars)			(Nominal dollars)	(2019 = 1.00)	(2019 Dollars)
			(2) x 2.153	[(1) x 1000]/(3)		(4)/(5)
	(1)	(2)	(3)	(4)	(5)	(6)
2013	$2,986.5	556,217	1,197,566	2.49	0.87	$2.88
2014	$5,218.5	554,162	1,193,142	4.37	0.90	$4.87
2015	$6,886.5	557,600	1,200,544	5.74	0.92	$6.21
2016	$6,868.5	561,885	1,209,771	5.68	0.94	$6.06
2017	$6,238.0	564,066	1,214,467	5.14	0.95	$5.42
Estimated Annual Weighted Meter O&M Expense (Average of 2014-2017)						**$5.6**

Table A.2.16 Lighting O&M per Light

Year	Lighting O&M Expenses	Number of Lights	Lighting Expenses Per Light	Labor and Materials Cost Index	Expense Per Light
	('000 Dollars)		(Dollars)	(2019=1.00)	(2019 Dollars)
2013	$582	57,687	10.09	86.66	0.12
2014	$676	57,687	11.71	89.81	0.13
2015	$725	57,687	12.56	92.32	0.14
2016	$940	57,687	16.30	93.71	0.17
2017	$633	57,687	10.97	94.71	0.12
Annual Lighting O&M Expense for Planning Period (Average of 2013-2017)					**$0.13**

Table A.2.17 Derivation of Time-Differentiated Bulk Station and Distribution Marginal Costs per kW and per kWh using Current TOU Periods (No Seasonality)

			Year-round Peak	Year-round Off-Peak
			(2019 Dollars per kWh)	
	Distribution Substation Relative Probability of System Peak:			
(1)	**Current TOU Periods - POP**		88.70%	11.30%

	Bulk Substation Losses Through Levels		Peak	Off-Peak	Dist. Substation Losses Through Levels		Peak	Off-Peak
(2)	Secondary		1.0518	1.0518	Secondary		1.0417	1.0417
(3)	Primary		1.0460	1.0460	Primary		1.0360	1.0360

	Bulk Substation Annual MC (System Wide Average)		Peak	Off-Peak	**Dis. Substation Annual MC (System-Wide Average)**		Peak	Off-Peak
(4)	$/kW-yr	12.82	11.3707	1.4484		$1.49	1.32	0.17
(5)	$ per kW per month		0.9476	0.1207			0.1102	0.0140
(6)	Hours by Costing Period:		3,246	5,514			3,246	5,514
(7)	$/kWh: (4)/(6)		0.0035	0.0003			0.0004	0.0000

		Bulk Substation Year-round Peak	**Bulk Substation** Year-round Off-Peak		**Distribution Substation** Year-round Peak	**Distribution Substation** Year-round Off-Peak
	COST PER KWH ($/kWh)			**COST PER KWH ($/kWh)**		
(8)	Secondary Cost adjusted by losses (2) x (7)	0.0037	0.0003	Secondary Cost adjusted by losses (2) x (7)	0.0004	0.0000
(9)	Primary Cost (3) x (11)	0.0037	0.0003	Primary Cost (3) x (11)	0.0004	0.0000
	COST PER KW ($/kW-mo)			**COST PER KW ($/kW-mo)**		
(10)	Secondary Cost adjusted by losses	0.9967	0.1270	Secondary Cost adjusted by losses	0.1148	0.0146
(11)	Primary Service	0.9912	0.1263	Primary Service	0.1141	0.0145

Table A.2.18 Derivation of Time-Differentiated Bulk Station and Distribution Marginal Costs per kW and per kWh using Option A TOU Periods

		Peak Summer (Jul/Aug)		NonSummer		Peak Summer (Jul/Aug)		NonSummer
		Peak	Off-Peak	All Hours				
	Distribution Substation Relative Probability of System Peak:							
(1)	**OPTION A - TOU Periods**	82.45%	12.83%	4.72%				
	Bulk Substation Losses Through Levels				Dist Substation Losses			
(2)	Secondary	1.0518	1.0518	1.0518	Secondary	1.0417	1.0417	
(3)	Primary	1.0460	1.0460	1.0460	Primary	1.0360	1.0360	
	Bulk Substation Annual MC (System Average)				**Distrib Subst. System-Wide Average**	Peak	Off-Peak	All Hours
(4)	**12.82** $/kW-yr	10.5694	1.6452	0.6045	**$1.49**	$1.23	$0.19	$0.07
(5)	$ per kW per month (cost/no. months)	5.2847	0.8226	0.0604		0.6144	0.0956	0.0070
(6)	Hours by Costing Period:	298	1,166	7,296		298	1,166	7,296
(7)	$/kWh (no loss adjusted): (4)/(6)	0.0355	0.0014	0.0001		0.0041	0.0002	0.0000
		Peak Summer (Jul/Aug)		NonSummer		Peak Summer (Jul/Aug)		NonSummer
	COST PER KWH ($/kWh)	Peak	Off-Peak	All Hours		Peak	Off-Peak	All Hours
	Adjusted by losses							
(8)	Secondary Service (2) x (7)	0.0373	0.0015	0.0001		0.0043	0.00017	0.00
(9)	Primary Service (3) x (7)	0.0371	0.0015	0.0001		0.0043	0.00017	0.00
	COST PER KW/MONTH ($/kW)							
(10)	Secondary Service (2) x (5)	5.5587	0.8653	0.0636		0.64	0.10	0.01
(11)	Primary Service (3) x (5)	5.5280	0.8605	0.0632		0.64	0.10	0.01

Table A.2.19 Derivation of Time-Differentiated Bulk Station and Distribution Marginal Costs per kW and per kWh using Option A TOU Periods

			Peak Summer (June- Sep)		NonSummer
			Peak	Off-Peak	All Hours
	Distribution Substation Relative Probability of System Peak:				
(1)	**OPTION B - TOU Periods**		86.97%	13.03%	0.00137%
	Bulk Substation Losses Through Levels				
(2)	Secondary		1.0518	1.0518	1.0518
(3)	Primary		1.0460	1.0460	1.0460
	Bulk Substation (System-Average)				
(4)		**$12.82** $/kW-yr	11.1487	1.6703	0.0002
(5)	$ per kW per month (cost/no. months)		2.7872	0.4176	0.0000
(6)	Hours by Costing Period:		596	2,332	5,832
(7)	$/kWh (no loss adjusted): (4)/(6)		0.0187	0.0007	0.0000
			Peak Summer (June- Sep)		NonSummer
	COST PER KWH ($/kWh)		Peak	Off-Peak	All Hours
	Adjusted by losses				
(8)	Secondary Service (2) x (7)		0.0197	0.0008	0.0000
(9)	Primary Service (3) x (7)		0.0196	0.0007	0.0000
	COST PER KW/MONTH ($/kW)				
(10)	Secondary Service (2) x (5)		2.9317	0.4392	0.0000
(11)	Primary Service (3) x (5)		2.9155	0.4368	0.0000

				NonSummer
	Dist Substation Losses			
(2)	Secondary		1.0417	1.0417
(3)	Primary		1.0360	1.0360
	Dist. Subst (System Average)	Peak	Off-Peak	All Hours
(4)	**$1.49**	$1.30	$0.19	$0.0000
(5)		0.3240 -	0.0485	0.0000
(6)		596	2,332	5,832
(7)		0.0022	0.0001	0.0000
		Peak Summer (June- Sep)		NonSummer
		Peak	Off-Peak	All Hours
(8)		0.00	0.00	0.0000
(9)		0.00	0.00	0.0000
(10)		0.34	0.05	0.0000
(11)		0.34	0.05	0.0000

Table A.2.20 Derivation of Revenue Requirement for Cash Working Capital Factor

I. Derivation of Overall Return:

	Incremental Capital Structure (1)		Incremental Cost of Capital (2)		Weighted Cost of Capital (3)
Debt	46.50%	x	5.00%	=	2.3250%
Common Equity	53.50%	x	10.50%	=	5.6175%
Overall Return = Composite Incremental Cost of Capital				=	7.9425%

II. Derivation of Income Tax Component:

) Income Tax Component

$$= \frac{27.241\ \%}{72.76\ \%} \times (\ .62\%)$$

$$= 2.10\%$$

III. Derivation of Revenue Requirement for Working Capital Factor:

Overall Return	=	7.94%
Income Tax Component	=	2.10%
Capital Factor	=	10.05%

Table A.2.21 Customer Account Expense by Customer Class

Class	Weighting Factor	Marginal Customer Accounts Expense
		------- (2019 $/cust) --
Residential Power & Light	1.00	$57.70
Residential OTOD	1.00	$57.70
Residential Controlled WH	-	$0.00
Residential LCS	-	$0.00
Residential Uncontrolled WH	-	$0.00
General Service Power & Light 1 Phase	1.41	$81.40
General Service Power & Light 3 Phase	1.41	$81.40
General Service OTOD 1 Phase	1.41	$81.40
General Service OTOD 3 Phase	1.41	$81.40
General Service Uncontrolled WH	-	$0.00
General Service Controlled WH	-	$0.00
General Service LCS 1 Phase	-	$0.00
General Service LCS 3 Phase	-	$0.00
General Service Space Heating	-	$0.00
Rate GV	4.52	$260.98
Rate LG	3.10	$178.76
Rate OL	0.16	$9.43
Rate EOL	0.13	$7.26

Table A.2.22 Customer Account Expense per Weighted Customer Numbers

	Year				
	2014	2015	2016	2017	Average
(1) Total Customer Accounts Expense (000's Dollars)	$32,405.1	$34,225.9	$29,651.4	$28,814.3	
(2) Average Number of Customers	504,040	503,321	508,019	513,316	
(3) Weighted Average Number of Customers	538,723	537,955	542,976	548,637	
(4) Customer Accounts Expense Per Weighted Customer	$60.15	$63.62	$54.61	$52.52	
(5) Labor Cost Index (2019 = 1.00)	0.86	0.89	0.92	0.94	
(6) Customer Accounts Expense Per Weighted Customer (2019 Dollars)	$69.73	$71.61	$59.68	$55.72	
(7) Estimated Annual Weighted Customer Accounts Expense (Average 2016-2017)					**$57.70**

Table A.2.23 Customer Service and Informational Expense per Weighted Customer Numbers

	Year				
	2014	2015	2016	2017	Average
(1) Total Customer Service and Informational Expense (000's Dollars)	$17,562.30	$16,025.58	$16,145.63	$16,301.44	
(2) Average Number of Customers	504,040	503,321	508,019	513,316	
(3) Weighted Average Number of Customers	837,657	836,463	844,270	853,073	
(4) Customer Service and Informational Expense Per Weighted Customer (Dollars)	$20.97	$19.16	$19.12	$19.11	
(5) Labor Cost Index (2019 = 1.00)	0.89	0.92	0.94	0.97	
(6) Customer Service and Informational Expense Per Weighted Customer (2019 Dollars)	$23.60	$20.94	$20.29	$19.68	
(7) Estimated Annual Weighted Customer Service and Informational Expense (Average 2016-2017)					**$19.99**

Table A.2.24 Customer Service and Informational Expense by Customer Class

Class	Weighting Factor	Marginal Customer Service and Informational Expense
		(2019 $/cust)
Residential Power & Light	1.00	$19.99
Residential OTOD	1.00	19.99
Residential Controlled WH	-	-
Residential LCS	-	-
Residential Uncontrolled WH	-	-
General Service Power & Light 1 Phase	1.00	19.94
General Service Power & Light 3 Phase	1.00	19.94
General Service OTOD 1 Phase	1.00	19.94
General Service OTOD 3 Phase	1.00	19.94
General Service Uncontrolled WH	-	-
General Service Controlled WH	-	-
General Service LCS 1 Phase	-	-
General Service LCS 3 Phase	-	-
General Service Space Heating	-	-
Rate GV	124.25	2,483.14
Rate LG	1,657.58	33,126.95

Table A.2.25 Economic Carrying Charge by Asset Type

	Distribution Substations	Distribution Facilities	Meters	Street Lights
Total Present Value Cost Related to Incremental $1,000 Investment	1,486.17	1,486.25	1,464.63	1,332.55
First-Year Annual Economic Charge Related to Incremental $1,000 Investment	84.31	90.92	93.68	$111.03
First-Year Annual ECC Related to Incremental Investment	8.43%	9.09%	9.37%	11.10%