Cost of Service and Cost Allocation Report

Adopted Rates 2019-2020

January 14, 2019

Contents

Executive Summary

The Cost of Service and Cost Allocation Study allocates the revenue requirements among customer classes based on the relative cost it takes to serve them.

The first step in the cost of service study is to unbundle the revenue requirement into service categories. **Table E.1** shows a summary of the unbundled revenue requirements for 2018-2020.

Table E.1: Unbundled Revenue Requirement Summary

$M	2018[1]	2019	2019 vs. 2018	2020	2020 vs. 2019
Energy	$574.1	$579.2	$5.1	$602.2	$23.0
Retail Services	$392.1	$417.8	$25.7	$436.6	$18.8
Net Wholesale Revenue Credit	-$60.0	-$55.0	$5.0	-$50.0	$5.0
Total	**$906.2**	**$942.1**	**$35.9**	**$988.8**	**$46.8**

Note that the revenue requirement shown here is higher than the revenue requirement found in the Revenue Requirement Analysis (RRA) because the RRA treats rate discounts as an expense for unbundling purposes. Table 2.1 in Section 2 of this report shows the relationship between the unbundled revenue requirement and the RRA revenue requirement. The 2019 and 2020 increases in the unbundled revenue requirement are driven by both energy costs and retail service costs.

After unbundling the revenue requirement, the next steps in the Cost of Service Study are developing costs of service and using them to allocate the revenue requirements to customer classes, as shown in **Table E.2**.

Table E.2: 2017 and 2018 Allocated Revenue Requirements

	Revenue Requirement		Percentage	
Customer Class	**2019**	**2020**	**2019**	**2020**
Residential	$369,568,005	$389,874,456	39%	39%
Small	$120,731,179	$125,937,646	13%	13%
Medium	$214,156,779	$224,138,080	23%	23%
Large	$138,234,900	$144,936,129	15%	15%
High Demand	$83,339,509	$87,254,844	9%	9%
Lights	$16,020,547	$16,655,628	2%	2%
Total	**$942,050,918**	**$988,796,784**	**100%**	**100%**

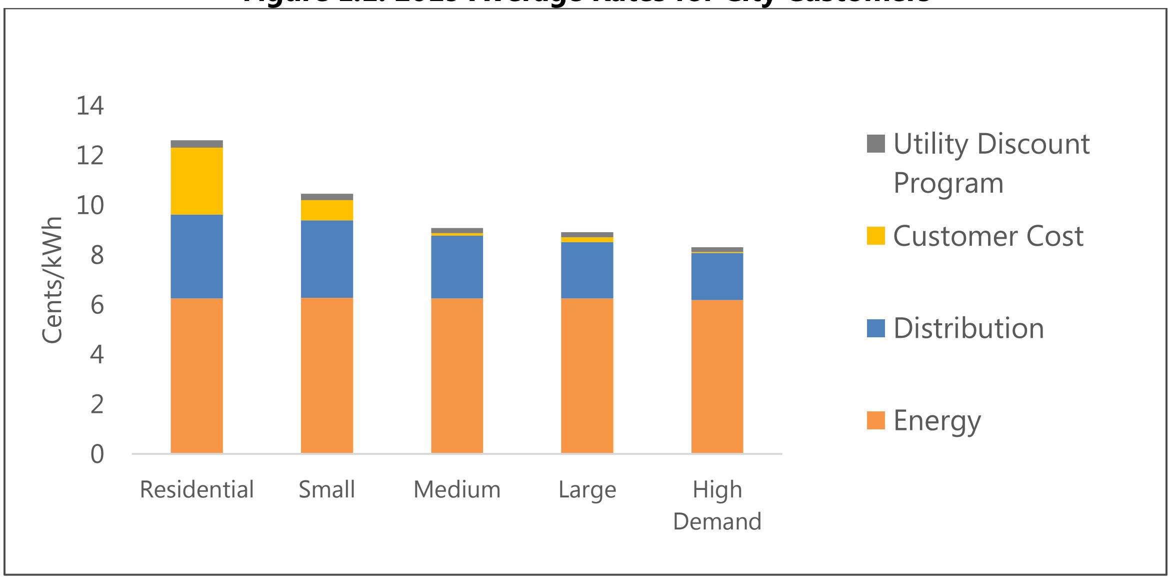
Average Rates

The average rate for each customer class is estimated by dividing the allocated revenue requirement by forecasted retail sales. The average rate for customers can be broken out into different service categories to illustrate why rates are different between customer classes.

[1] From 2018 Adopted Cost of Service and Cost Allocation Report, adjusted for the 2017 BPA passthrough.

Figure E.1 shows the average rate for each customer class in the City of Seattle. Residential and small general service customers recover fixed costs (e.g., billing costs, meter costs) over fewer kWh, which increases their average rate per kWh compared to other customer classes. As can be seen, average energy costs are very similar across all customer classes.

Figure E.1: 2019 Average Rates for City Customers



Changes to Average Rates

The below table summarizes the changes to the average rates for 2019 and 2020. The 2020 system-wide average rate impact of 5.5% is slightly higher than the 5.4% reported in the 2019-2024 Strategic Plan due to the average rates being calculated before rate discounts in the Cost of Service Study.

Table E.3 Summary of Percentage average Rate Changes by rate class

2019	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**
All Areas	5.8%	6.6%	4.4%	5.6%	4.3%	5.9%
Non-Network	5.7%	6.6%	4.4%	4.7%	4.3%	5.9%
Downtown Network	6.2%			8.4%	4.3%	
2020	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**
All Areas	5.5%	4.9%	5.4%	5.8%	6.0%	5.8%
Non-Network	5.4%	4.9%	5.4%	5.5%	5.5%	5.8%
Downtown Network	6.5%			6.5%	6.4%	

1. Introduction

The Cost of Service and Cost Allocation Report (COSACAR) details the costs of providing service to City Light customers and describes the methodology used to allocate revenue requirements to each rate class. This is the second step of a three-step rate review process comprised of a revenue requirement analysis, a cost of service analysis, and rate design.

Resolution 31351, adopted by the City Council in May 2012, establishes City Light's cost allocation principles. They are:

1. *Customer Payment Based on Cost of Service.* To encourage the efficient use of resources, rates should be based on the marginal cost of service to the customer and should reflect changes in the marginal cost over time.
2. *Equity.* Rates should reflect a fair apportionment of the different costs of providing service among groups of customers.
3. *Conservation Expense.* Since the City considers that conservation is a power resource, conservation expenditures shall be allocated to all customer rate classes.
4. *Utility Discount Program (UDP) Rates and Bill Payment Assistance Expense.* The costs of providing UDP rates and bill payment assistance to low-income residential customers shall be allocated to all customer classes.

The methodology for this cost of service study is the same as that used in the last full rate review (for 2017-2018 rates) and can be summarized in these three steps:

1. **Functionalization:** Revenue requirements are allocated to functional cost categories that correspond to the services provided (energy, distribution, customer service), plus the subsidy for UDP customers and a credit for net wholesale power revenue. For wires and related equipment and customer transformers only, the functionalized revenue requirements are separated into network and non-network components.

2. **Cost of Service and Allocation Factors:** Marginal costs for various service components (energy, transmission, substations, etc.) are calculated. The annual total cost of providing each of the services to each customer class is computed, with services valued at their respective marginal cost. Allocation factors are computed by dividing the total cost of each service for each customer class by the total cost of each service for all customers. This is done separately for network and non-network wires and transformers.

3. **Cost Allocation:** The allocation factors are used to divide the functionalized revenue requirements among customers for each of the two years. This is done separately for network and non-network wires and transformers. After this initial allocation of revenue requirements, adjustments reflecting franchise city agreements and Council policy directives are incorporated.

The rest of the report presents the details of the three steps described above to allocate the 2019 and 2020 revenue requirement among customer classes.

2. Functionalization

This section describes how the revenue requirement is assigned to functionalized categories such as energy, distribution, customer care and the UDP. The conversion process is also known as "unbundling" the revenue requirement. City Light has been unbundling the customer revenue requirement since the 1997-1998 rate review.

2.1 Results and Summary

The unbundling of revenue requirements for 2019-2020 follow the same methodology as that used in the 2017-2018 rate review. **Table 2.1** summarizes the functionalized revenue requirements for 2019 and 2020.

Table 2.1: Summary of Unbundled Revenue Requirements for 2019 and 2020

$ Millions	**2019**	**2020**
Total Energy	**$579.2**	**$602.2**
Power	455.6	474.5
Conservation	58.8	61.0
Transmission-Long Distance	64.9	66.7
Total Retail Services	**$417.8**	**436.6**
Total Distribution	294.6	308.4
Transmission-In-Service-Area	18.6	19.4
Stations	49.3	50.9
Wires and Related Equipment	184.4	193.7
non-network	*136.2*	142.7
network	*48.3*	51.1
Transformers	29.0	30.5
non-network	*14.6*	15.5
network	*14.4*	15.1
Streetlights/Floodlights	13.3	13.9
Total Customer Care	99.6	102.4
Meters	16.4	17.0
Other	83.2	85.4
Rate Discounts (UDP)	23.7	25.8
Subtotal	**$997.1**	**1,038.8**
Net Wholesale Revenue Credit	-$55.0	-$50.0
Unbundled Revenue Requirement	**$942.1**	**$988.8**
Rate Discounts	-19.4	-21.3
Revenue Requirement (Strategic Plan)	$922.7	$967.5

The unbundled revenue requirement does not match the revenue requirement published in the Revenue Requirement Analysis (RRA); it is higher because it treats rate discounts as an outflow in order to allocate them to customer classes.

The net outflows allocated to each functionalized category are calculated by adding net direct cash outflows and various indirect, or assigned/allocated, net cash outflows. Assigned/allocated net cash outflows include administration and general (A&G) payments, revenue and county tax payments, principal and interest payments on debt (net of interest receipts), cash capital contributions, cost of capital and the risk management premium.

Table 2.2 details dollars assigned to each functional category for 2019 and 2020. Each functional category is discussed individually in the following sections.

Table 2.2: Unbundled Revenue Requirements 2019-2020

Table 2.2: Unbundled Revenue Requirements	**2019**		**2020**	
Functions	**$ Millions**	**$/MWh**	**$ Millions**	**$/MWh**
ENERGY				
Power				
Direct Cash Outflows (Inflows):				
Generation O&M	$57.1		$58.1	
Long-Term Purchased Power	229.6		238.7	
Power-Related Wholesale Purchases	4.2		4.2	
Interest Income on Cash Balances	(-1.2)		(-1.4)	
Article 49 Sales to Pend Oreille County	(-2.2)		(-2.2)	
Sales from Priest Rapids	(-1.6)		(-1.5)	
Power-Related Wholesale Sales	(-8.2)		(-5.6)	
Subtotal	277.7		290.4	
Indirect Cash Outflows (Inflows):				
Debt Service	40.3		42.3	
Administration and General	25.9		26.4	
Taxes and Payments in Lieu of Taxes:				
Revenue Taxes	38.7		41.0	
Whatcom County Contract Payments	1.1		1.2	
Pend Oreille County Contract Payments	1.9		1.9	
Subtotal	41.8		44.1	
Cost of Capital	31.6		33.7	
Risk Management Premium	38.4		37.7	
Total Power	**$455.6**	**$49.10**	**$474.5**	**$51.14**
Conservation				
Direct Cash Outflows (Inflows):				
Conservation	$9.2		$9.4	
Interest Income on Cash Balances	(-1.1)		(-1.2)	
Operating Fees (Lighting Lab)	(-0.3)		(-0.3)	
GreenUp and Community Solar Retail Sales	(-1.6)		(-2.1)	
Subtotal	6.2		5.8	
Indirect Cash Outflows (Inflows):				
Debt Service	34.9		36.6	

Table 2.2: Unbundled Revenue Requirements	2019		2020	
Functions	**$ Millions**	**$/MWh**	**$ Millions**	**$/MWh**
Administration and General	2.3		2.4	
Revenue Taxes	5.9		6.1	
Cost of Capital	9.5		10.1	
Total Conservation	**$58.8**	**$6.33**	**$61.0**	**$6.57**
Transmission-Long Distance				
Direct Cash Outflows (Inflows):				
Transmission O&M	$6.8		$6.9	
Wheeling	43.9		44.8	
Interest Income on Cash Balances	(-0.2)		(-0.2)	
Transmission Services	(-3.4)		(-3.4)	
Transmission Attachments & Cell Sites	(-0.9)		(-1.0)	
Subtotal	46.2		47.2	
Indirect Cash Outflows (Inflows):				
Debt Service	5.3		5.6	
Administration and General	4.2		4.3	
Taxes				
Oregon Tax on 3rd AC Intertie	0.2		0.2	
Revenue Taxes	6.4		6.5	
Subtotal	6.6		6.8	
Cost of Capital	2.6		2.8	
Total Transmission-Long Distance	**$64.9**	**$7.00**	**$66.7**	**$7.19**
TOTAL ENERGY	**$579.2**	**$62.43**	**$602.2**	**$64.90**
RETAIL SERVICES				
Transmission-In Service Area				
Direct Cash Outflows (Inflows):				
Transmission O&M	$5.2		$5.3	
Interest Income on Cash Balances	(-0.2)		(-0.2)	
Transmission Attachments & Cell Sites	(-0.7)		(-0.8)	
Subtotal	4.3		4.4	
Indirect Cash Outflows (Inflows):				
Capital Contributions and Grant Receipts	(-1.0)		(-1.0)	
Debt Service	6.1		6.4	
Administration and General	3.2		3.3	
Revenue Taxes	2.0		2.0	
Cost of Capital	4.0		4.3	
Total Transmission-In Service Area	**$18.6**	**$2.00**	**$19.4**	**$2.09**

Table 2.2: Unbundled Revenue Requirements	2019		2020	
Functions	**$ Millions**	**$/MWh**	**$ Millions**	**$/MWh**
Distribution-Stations				
Distribution O&M-Stations	$17.3		$17.6	
Interest Income on Cash Balances	(-0.4)		(-0.4)	
Gain on Sale of Distribution Assets	(-1.1)		(-1.2)	
Subtotal	15.8		16.1	
Indirect Cash Outflows (Inflows):				
Capital Contributions and Grant Receipts	(-1.8)		(-1.8)	
Debt Service	12.6		13.3	
Administration and General	14.0		14.3	
Revenue Taxes	5.0		5.2	
Cost of Capital	3.6		3.8	
Total Distribution-Stations	**$49.3**	**$5.31**	**$50.9**	**$5.48**
Distribution-Wires and Related Equipment				
Direct Cash Outflows (Inflows):				
Distribution O&M-Wires and Related Equipment	$43.0		$43.9	
Interest Income on Cash Balances	(-2.8)		(-3.1)	
Property Rental Receipts	(-2.7)		(-2.7)	
Damage Receipts	(-1.0)		(-1.0)	
Other O&M Receipts	(-6.5)		(-6.5)	
Pole Attachment Receipts	(-2.7)		(-2.7)	
Distribution Capacity Charge Receipts	(-0.2)		(-0.2)	
Power Factor Receipts	(-2.5)		(-2.5)	
Subtotal	24.5		25.0	
Indirect Cash Outflows (Inflows):				
Capital Contributions and Grant Receipts	(-20.9)		(-21.0)	
Debt Service	92.2		96.6	
Administration and General	23.2		23.7	
Revenue Taxes	21.3		22.3	
Cost of Capital	44.1		47.0	
Total Distribution-Wires and Related Equipment	**$184.4**	**$19.88**	**$193.7**	**$20.88**
Distribution-Transformers				
Direct Cash Outflows (Inflows):				
Distribution O&M-Transformers	$2.7		$2.8	
Interest Income on Cash Balances	(-0.5)		(-0.6)	
Credits for Customer-Owned Transformers	0.4		0.4	
Subtotal	2.6		2.7	

Table 2.2: Unbundled Revenue Requirements	2019		2020	
Functions	**$ Millions**	**$/MWh**	**$ Millions**	**$/MWh**
Indirect Cash Outflows (Inflows):				
Debt Service	16.4		17.2	
Administration and General	2.2		2.3	
Revenue Taxes	3.1		3.3	
Cost of Capital	8.1		8.7	
Total Distribution-Transformers	**$29.0**	**$3.12**	**$30.5**	**$3.29**
Distribution-Streetlights/Floodlights				
Direct Cash Outflows (Inflows):				
Distribution O&M-Lights	$2.7		$2.8	
Interest Income on Cash Balances	(-0.2)		(-0.2)	
Indirect Cash Outflows (Inflows):				
Capital Contributions and Grant Receipts	(-1.3)		(-1.3)	
Debt Service	6.1		6.4	
Administration and General	1.7		1.7	
Revenue Taxes	1.4		1.5	
Cost of Capital	2.8		3.0	
Total Distribution-Streetlights/Floodlights	**$13.3**	**$1.44**	**$13.9**	**$1.50**
SUBTOTAL DISTRIBUTION	**$276.0**	**$29.75**	**$289.1**	**$31.15**
TOTAL DISTRIBUTION + IN-SERVICE-AREA TRANSMISSION	**$294.6**	**$31.75**	**$308.4**	**$33.24**
Customer Care-Meters				
Direct Cash Outflows (Inflows):				
Distribution O&M-Meters	$3.9		$4.0	
Interest Income on Cash Balances	(-0.2)		(-0.2)	
Indirect Cash Outflows (Inflows):				
Debt Service	5.4		5.7	
Administration and General	3.3		3.4	
Revenue Taxes	1.6		1.6	
Cost of Capital	2.4		2.5	
Total Customer Care-Meters	**$16.4**	**$1.77**	**$17.0**	**$1.83**

Table 2.2: Unbundled Revenue Requirements	2019		2020	
Functions	**$ Millions**	**$/MWh**	**$ Millions**	**$/MWh**
Other Customer Care				
Direct Cash Outflows (Inflows):				
Customer Accounting and Advisory O&M	$45.5		$46.7	
Interest Income on Cash Balances	(-0.1)		(-0.1)	
Late Payment Fees	(-2.8)		(-2.8)	
Account Change Fees	(-1.9)		(-1.9)	
Reconnect Fees	(-0.1)		(-0.1)	
Subtotal	40.6		41.7	
Indirect Cash Outflows (Inflows):				
Debt Service	4.1		4.3	
Administration and General	29.7		30.3	
Revenue Taxes	8.5		8.7	
Cost of Capital	0.3		0.4	
Total Other Customer Care	**$83.2**	**$8.96**	**$85.4**	**$9.21**
Total Customer Care	**$99.6**	**$10.73**	**$102.4**	**$11.04**
Utility Discount Program				
Direct Cash Outflows (Inflows):				
Utility Discount Program O&M	$1.0		$1.0	
Rate Discounts	19.4		21.3	
Bill Payment Assist. from Low-Income Acct.	0.3		0.3	
Late Payment Fees	(-0.1)		(-0.1)	
Subtotal	20.6		22.5	
Indirect Cash Outflows (Inflows):				
Debt Service	0.1		0.1	
Administration and General	0.6		0.7	
Revenue Taxes	2.3		2.5	
Total Utility Discount Program	**$23.7**	**$2.55**	**$25.8**	**$2.78**
TOTAL RETAIL SERVICES	**$417.8**	**$45.03**	**$436.6**	**$47.06**
SUBTOTAL RETAIL CUSTOMER REVENUE REQUIREMENT BEFORE CREDIT	**$997.1**	**$107.46**	**$1,038.8**	**$111.96**
CREDIT FOR NET WHOLESALE POWER SALES	**(-$55.0)**		**(-$50.0)**	
TOTAL REVENUE REQUIREMENT	**$942.1**	**$101.53**	**$988.8**	**$106.57**

2.2 Direct Cash Outflows

Direct cash outflows (outflows) are O&M outflows that are directly incurred in providing City Light's services under each functional category. They are modified by cash inflow (inflows) offsets where appropriate.

2.2.1 Energy

Power: Direct generation outflows are those associated with the costs of running seven owned hydroelectric plants (Boundary, Ross, Diablo, Gorge, Cedar Falls, Newhalem, and South Fork of the Tolt) as well as system control and dispatch outflows. Direct purchased power outflows include those associated with long-term power contracts, including Bonneville Power Administration (BPA) Block, Lucky Peak, High Ross, Stateline Wind Project and others.

Other direct outflows and offsets in this category include:

- Basis purchase outflows net of basis sales inflows;
- Other power outflows, such as those associated with the automated system control center, checking the metering apparatus associated with power purchases as well as contract and environmental payments;
- Other power inflows, such as those associated with the sale of capacity and RECs (environmental benefits of energy generated from green resources), sales to Pend Oreille Public Utility District under Article 49 of the Boundary Project license, sales from the Priest Rapids Project (per contracts with Grant County PUD No. 1) and seasonal energy exchange deliveries.

Conservation: City Light policy is to treat conservation as an energy resource. Costs of installed conservation measures are amortized over 20 years; therefore, direct conservation outflows include only the costs related to annual planning, management, customer information and assistance. Inflows from operation of the Lighting Design Lab are netted against these outflows. Inflows from retail customers who make voluntary payments in support of City Light's Green Up and Community Solar programs are also netted against direct conservation outflows because they offset the cost of acquiring local renewable energy resources.

Long-Distance Transmission: Transmission O&M outflows are those related to either long-distance transmission (energy) or in-service-area transmission (retail services) costs. In most cases, Federal Energy Regulatory Commission (FERC) account names designate the nature of the transmission cost. However, a few cost categories (e.g., supervisory and engineering, load dispatching and other costs) are allocated between the two transmission sub-functions based on relative transmission labor hours.

Direct outflows associated with long-distance transmission include the costs of operating and maintaining City Light's owned transmission facilities, payments for the operation and maintenance of the utility's share of BPA's Third AC Intertie, and payments to other entities for transmitting power across their high voltage lines (called "wheeling").

Owned transmission outflows include payments for transmission load dispatching, switching stations, inspecting and testing lines, and engineering. Owned long-distance transmission facilities include lines that connect City Light's service territory to the Skagit, Cedar Falls, and Tolt projects as well as BPA connections. Wheeling outflows include payments to BPA and other utilities for transmission of power from Boundary, Lucky Peak, Grand Coulee and other facilities.

Transmission outflows are offset by inflows from:

- Transmission services, which are assigned to the long-distance sub-function. These inflows are primarily associated with wheeling Skagit power to Snohomish PUD territory and City Light's contractual reassignment of its share of the Third AC Intertie to third parties.
- A portion of rental inflows for transmission line attachments and cellular antenna sites, which are allocated to both transmission sub-functions based on the relative share of historical total transmission O&M costs.

2.2.2 Retail Services

In-Service-Area Transmission: Transmission O&M outflows are those related to either long-distance transmission (energy) or in-service-area transmission (retail services) costs. In most cases, Federal Energy Regulatory Commission (FERC) account names designate the nature of the transmission cost. However, a few cost categories (e.g., supervisory and engineering, load dispatching and other costs) are allocated between the two transmission sub-functions based on relative transmission labor hours.

Direct outflows associated with in-service-area transmission include the costs of operating and maintaining City Light's owned transmission facilities. Owned transmission outflows include payments for transmission load dispatching, switching stations, inspecting and testing lines, and engineering. City Light in-service-area transmission facilities include the Bothell and Beacon Hill switching stations, the Covington and Talbot Hill substations, Maple Valley to South Substation and South Renton to Duwamish substation facilities, Duwamish to Delridge and Delridge to South substation facilities, Bothell to Seattle lines, all underground transmission lines and equipment, and a few smaller transmission substations and lines. These outflows are reduced by allocated rental inflows from transmission line attachments and cellular antenna sites.

Distribution: Direct distribution outflows cover the O&M costs of the Department's distribution system (i.e., the lower voltage lines and associated equipment that bring energy to individual customers) and are comprised of costs associated with distribution supervision and engineering, load dispatching and substations, overhead and underground lines, public lighting, meters, poles, vaults, ducts, and transformers.

Direct distribution outflows are allocated among four distribution sub-functions: substations (stations), wires and related equipment (wires), transformers, and streetlights/floodlights (lights), and one customer care sub-function (meters). The allocation of forecasted distribution O&M outflows among these five sub-functions prior to inflow offsets is based on average 2013-2015 expenses and labor hours.

Table 2.3 summarizes percentages of direct distribution expenses that were allocated to the distribution and customer care sub-functions.

Table 2.3: Direct Distribution Expenses Allocation Percentages 2019-2020

	2019	2020
Stations	25.8%	25.8%
Wires	61.3%	61.2%
Transformers	3.4%	3.3%
Lights	3.9%	3.9%
Distribution Sub-Function	**94.3%**	**94.3%**
Customer Care (meters) Sub-Function	**5.7%**	**5.7%**

Two distribution sub-functions have modifications to O&M outflows:

- Wires include an offset for inflows from property rental and damages, construction charges, pole attachments, power factor charges, reserved distribution capacity charges, and other sundry charges (e.g., equipment maintenance).
- Transformers include an additional outflow for transformer investment discounts, which are credited to customers who supply their own transformers.

LED conversion is expected to significantly reduce future O&M outflows associated with lights, making historical data an inaccurate indicator of future outflows. Consequently, O&M outflows allocated to lights calculated under this method were reduced with the difference allocated across the remaining distribution sub-functions.

Customer Care: Direct outflows in this category cover meter reading and meter-related distribution costs, records and collections, uncollectible accounts, and customer information and assistance (except amounts related to conservation and UDP). These outflows are reduced by inflows from late payment fees, account change fees, miscellaneous equipment rentals and reconnect charges.

Utility Discount Program (UDP): City Light provides reduced electric rates, bill payment assistance and fee waivers for qualified low-income residential customers. Direct outflows for this category include estimated O&M outflows related to UDP activities charged under customer care (e.g., credit, collections and the work of customer service representatives), which are estimated based on historical labor hours devoted to UDP activities. Other elements of the revenue requirement included in UDP direct outflows are foregone inflows for the rate discount and account change fee waivers, outflows from City Light's UDP account for bill payment assistance and administrative costs paid to the Human Services Department (HSD). Inflows from late payment fees offset the foregoing outflows.

2.3 Assigned and Allocated Cash Outflows (net)

Contributions in Aid of Construction (CIAC) and Grants: CIAC includes payments from customers for electrical service installation charges, non-standard service (e.g., underground service or a second feeder), feeder relocation or replacements, and other contributions. Grants are payments from government agencies to cover costs of a requested project. 2019 and 2020 forecasted contributions relate primarily to distribution projects though a minor amount is attributable to transmission projects. To smooth out the variation in annual contributions, a three-year average of historical contributions was allocated/assigned to functionalized categories, which include in-service-area transmission and all distribution categories. Depreciation, as a measure of the depleted resources that will require future contributions, was used to allocate the three-year average for all CIAC and grant inflows except for suburban undergrounding-related inflows, which were directly assigned to the wires and related equipment sub-function.

Principal and Interest Payments: This category includes principal and interest payments on debt with an offset from interest receipts. Principal and interest payments were allocated to all functional categories based on the depreciation and amortization recorded on plant in those categories as well as an allocated share of these expenses recorded on general plant assets through the end of 2014. Deferred assets were assigned to functional categories as follows: unamortized hydro project relicensing, High Ross and Skagit endowment to production and purchased power (power), unamortized programmatic conservation measures to conservation, and unamortized Puget Stillwater Substation to long-distance transmission. The depreciation and amortization expenses on which principal and interest payment allocations are based are shown in **Table 2.4**.

Table 2.4: Book Values & Depreciation/Amortization of Plant & Deferred Debits - 2014

	Book Value	%	Depreciation and Amortization	%
Power	**$759.2**	**28.9%**	**$22.2**	**18.0%**
Hydroelectric Plant	473.2		15.0	
Share of General Plant	30.0		3.6	
Unamortized Hydro Project Relicensing	108.3		3.3	
Unamortized High Ross and Skagit Endowment	147.7		0.3	
Conservation	**228.6**	**8.7%**	**19.2**	**15.6%**
Unamortized Conservation	228.1		19.1	
Share of General Plant	0.5		0.1	
Transmission				
Long-Distance Transmission	**63.4**	**2.4%**	**2.9**	**2.4%**
Transmission Plant	59.2		2.3	
Share of General Plant	3.5		0.7	
Unamortized Puget Stillwater Substation	0.6		0.0	
In-Service Area Transmission	**97.3**	**3.7%**	**3.3**	**2.7%**
Transmission Plant	91.9		3.0	
Share of General Plant	5.5		0.4	
Distribution				
Stations	**86.0**	**3.3%**	**7.0**	**5.7%**
Distribution Plant	81.7		4.3	
Share of General Plant	4.3		2.6	
Wires and Related Equipment	**1,059.9**	**40.4%**	**50.8**	**41.2%**
Distribution Plant	1,007.4		46.8	
Share of General Plant	52.5		4.0	
Transformers	**195.6**	**7.5%**	**9.0**	**7.3%**
Distribution Plant	185.9		8.6	
Share of General Plant	9.7		0.4	
Streetlights/Floodlights	**68.3**	**2.6%**	**3.3**	**2.7%**
Distribution Plant	64.9		3.1	
Share of General Plant	3.4		0.3	
Customer Care				
Meters	**56.8**	**2.2%**	**3.0**	**2.4%**
Distribution Plant	54.0		2.4	
Share of General Plant	2.8		0.6	
Other Customer Care	**8.3**	**0.3%**	**2.3**	**1.8%**
Share of General Plant	8.3		2.3	
Utility Discount Program	**0.2**	**0.0%**	**0.0**	**0.0%**
Share of General Plant	0.2		0.0	
Total	**$2,623.7**	**100.0%**	**$123.2**	**100.0%**

A&G Outflows: A&G outflows include payments for administrative salaries, office supplies, outside services, property insurance, injuries and damages, employee pensions and benefits, rents, general plant maintenance and miscellaneous general payments. The A&G outflows are allocated by percentages of non-A&G labor hours in each functional category for 2014.

State and City Taxes, Franchise Payments and County Payments: City Light pays a public utility tax to the State of Washington (3.8734%) and an Occupation tax to the City of Seattle (6.0%). In addition, City Light pays business taxes to both jurisdictions. State and City taxes are allocated to the functional categories proportionately based on each category's size. City Light also pays an Oregon tax on City Light's portion of the Third AC transmission intertie, which is directly allocated to long-distance transmission expenses.

Contract payments to suburban cities with which City Light has franchise agreements are not taxes but are similarly calculated based on revenue. These are also allocated to the functional categories proportionately based on each category's size.

In addition, payments are made to county governments for services provided in counties where City Light has generation facilities. Services include fire and police protection, schools, and road maintenance. Payments are made to Whatcom County for services associated with the Skagit projects and to Pend Oreille County for services related to the Boundary project.

Net Cash Inflow: City Light's net cash inflow is the residual after all cash inflows and outflows are considered. Net cash inflow contributes to the Utility's equity. The net cash inflow allocation procedure assumes a 7% return on expected capital, which corresponds generally to City Light's discount rate policy. Each functional category is allocated a portion of the cost of capital based on relative book value shares outlined in **Table 2.4.** The remaining net cash inflow is assigned to the power component as a risk management premium due to the weather-related variability of power supply.

2.4 Non-network and Network Cash Outflows (net)

Two distribution sub-functions (wires and related equipment, and transformers), are further split into non-network and network components. The network cost components shown below include all City Light's current network areas (Downtown, First Hill, University District), not just the area assigned Downtown Network rates. In addition, the downtown network will start gradually expanding northward once the new Denny substation is energized. For cost allocation purposes, approximately 86% (2019) and 87% (2020) of the network outflows shown below are allocated to the Downtown Network; this allocation is based on historical consumption percentages (85%) and includes some mild growth for north downtown customers who will begin receiving network service in 2019 and 2020. The other 14% (2019) and 13% (2020) of the network outflows shown are reallocated back to non-network classes because, at the present time, First Hill, and University District network customers are treated as non-network customers for rate-making purposes.

Operating and Maintenance (O&M): O&M outflows (net) are allocated between non-network and network components based on direct assignment where the net outflow clearly applies to one component (e.g., maintenance of underground network equipment is assigned to the network component). Historical labor hours are used to allocate any net outflows applicable to both components (e.g., supervision, load dispatching and safety programs).

- Wires and Related Equipment: non-network 91.2%; network 8.8%
- Transformers: non-network 9.4%; network 90.6%

Capital: Contribution and grant inflows, debt service outflows (net of interest receipts) and cost of capital are allocated between non-network and network components based on each component's average relative percentage of capital additions from 1993-2014. The long-term nature of the allocator is intended to remove biases associated with short-term investment decisions.

- Wires and Related Equipment: Non-network 66.0%; network 34.0%
- Transformers: Non-network 60.1%; network 39.9%

Administrative and General (A&G): A&G outflows are allocated between non-network and network components based on historical labor hours.

- Wires and Related Equipment: Non-network 90.1%; network 9.9%
- Transformers: Non-network 7.5%; network 92.5%

Taxes: Taxes are allocated between non-network and network categories by using the relative share of costs for all net outflows, excluding tax payments.

The 2019 and 2020 non-network/network breakdown of projected revenue requirements for wires and related equipment and transformers is shown in **Table 2.5**.

Table 2.5: 2019 and 2020 Non-network/Network Cash Outflows (net)

	2019		2020	
Wires and Related Equipment	**Non-network**	**Network**	**Non-network**	**Network**
Wires and Related Equipment	**$39.2**	**$3.8**	**$40.0**	**$3.8**
Property Rental Inflows	(-2.5)	(-0.2)	(-2.5)	(-0.2)
Inflows from Damage	(-0.9)	(-0.1)	(-0.9)	(-0.1)
Other O&M Inflows	(-5.9)	(-0.6)	(-6.0)	(-0.6)
Construction (Installation) Inflows	(-0.0)	(-0.0)	(-0.0)	(-0.0)
Pole Attachment Inflows	(-2.7)	0.0	(-2.7)	0.0
Distribution Capacity Inflows	(-0.2)	0.0	(-0.2)	0.0
Power Factor Inflows	(-2.3)	(-0.2)	(-2.3)	(-0.2)
Subtotal	**$24.7**	**$2.7**	**$25.4**	**$2.7**
Contributions and Grant Inflows	(-13.8)	(-7.1)	(-13.9)	(-7.1)
Debt Service Payments	59.0	30.4	61.7	31.8
Administrative and General Outflows	20.9	2.3	21.4	2.4
Tax Payments	16.3	5.1	17.0	5.3
Cost of Capital and Risk Management	29.1	15.0	31.0	16.0
Total Wires and Related Equipment	**$136.2**	**$48.3**	**$142.7**	**$51.1**

	2019		2020	
Transformers	**Non-network**	**Network**	**Non-network**	**Network**
Distribution O&M-Transformers	**$0.3**	**$2.5**	**$0.3**	**$2.5**
Customer-Owned Transformer Credits	0.4	0.0	0.4	0.0
Subtotal	**$0.7**	**$2.5**	**$0.7**	**$2.5**
Contributions and Grant Inflows	(-2.1)	(-1.4)	(-2.1)	(-1.4)
Debt Service Payments	9.5	6.3	10.0	6.6
Administrative and General Outflows	0.2	2.1	0.2	2.1
Tax Payments	1.5	1.7	1.5	1.7
Cost of Capital and Risk Management	4.9	3.3	5.2	3.5
Total Transformers	**$14.6**	**$14.4**	**$15.5**	**$15.1**

3. Cost of Service Allocation Factors

3.1. Marginal Cost Approach

City Light uses a marginal cost approach in estimating the cost of providing services to customers for purposes of allocating revenue requirements. Marginal costs measure how a utility's cost picture changes when cost of inputs changes, load is changed and/or the number of customers in the system changes. Only current (or near term future) costs are included in the marginal cost estimates. Average costs, by contrast, are derived by dividing a utility's total costs by total load, maximum demand, or the number of customers. A marginal cost approach was used in every comprehensive City Light rate case since 1980.

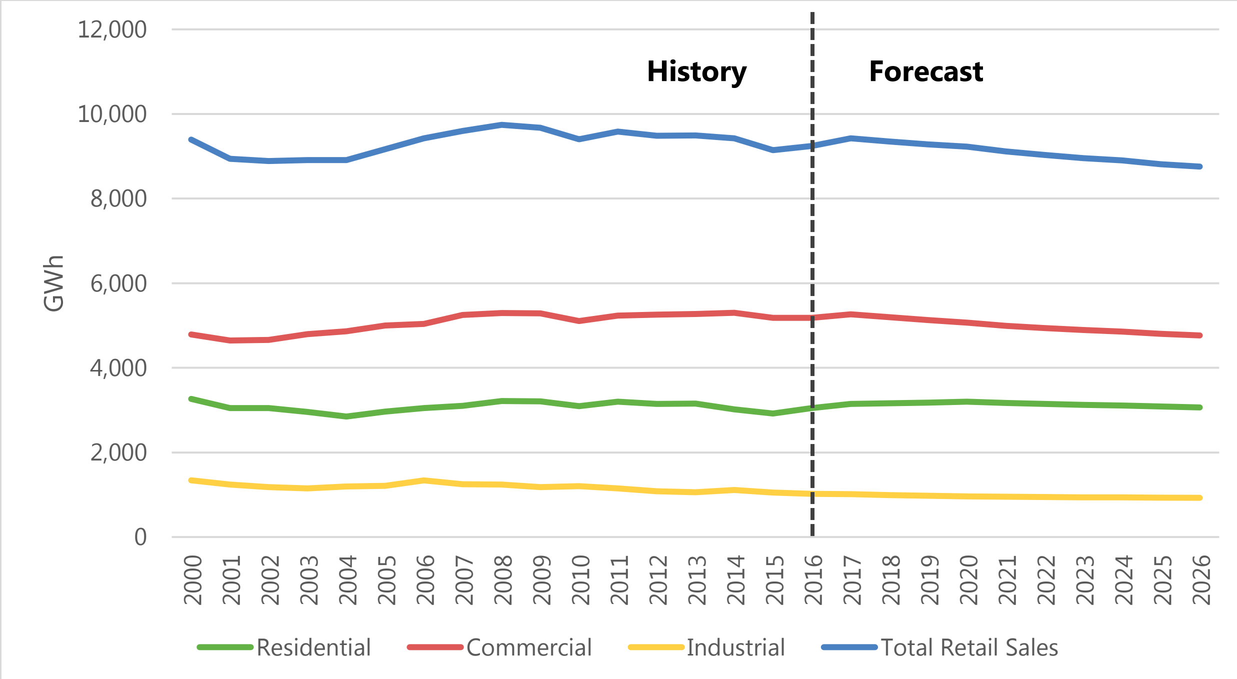
3.2. Load Overview

The retail load forecast is the single most important input for determining the total cost of energy and for allocating the total energy cost to individual customer classes and service areas. In addition, load data is used to allocate certain distribution costs.

3.2.1. History and Forecast

City Light's retail load forecast is based on forecasts of selected economic drivers for the service territory and includes assumptions about energy efficiency, City Light sponsored conservation, electrification, distributed generation and climate change. **Figure 3.1** shows the retail load forecast that was produced in the winter of 2017. The forecast projects low load growth for the commercial sector and flat to declining growth for the residential and industrial sectors.

Figure 3.1: City Light Load History and Forecast



To develop the billing determinants, the commercial and industrial load is allocated into Small, Medium, Large and High Demand customer classes based on historical sales. Load is further divided into network and non-network classes. **Tables 3.1** and **3.2** show forecasted consumption by customer class for 2019 and 2020, respectively.

Table 3.1: Energy Consumption by Customer Class in 2019

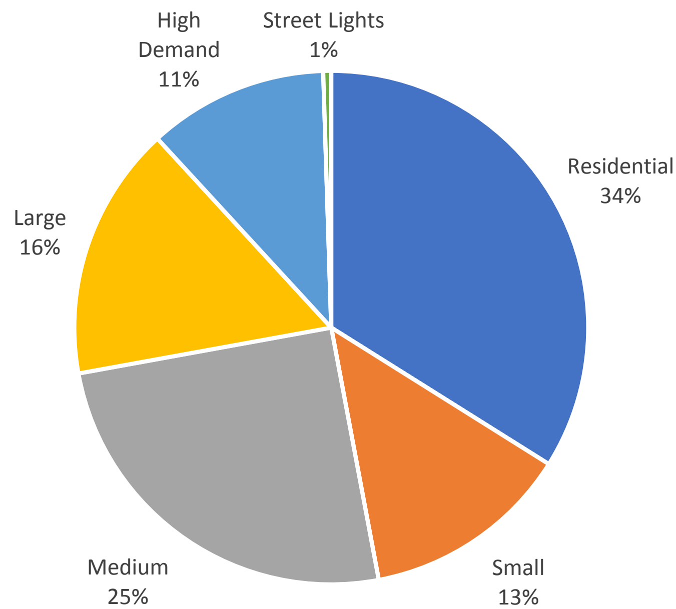
2019	Total	Residential	Small	Medium	Large	High Demand	Lights
Service Territory	9,278,592	3,147,427	1,216,991	2,329,211	1,487,492	1,050,943	46,529
Non-network	7,977,229	3,060,754	1,083,348	1,847,115	888,540	1,050,943	46,529
Network	1,301,363	86,673	133,643	482,096	598,951		

Table 3.2: Energy Consumption by Customer Class in 2020

2020	Total	Residential	Small	Medium	Large	High Demand	Lights
Service Territory	9,230,139	3,165,052	1,204,596	2,304,584	1,471,865	1,040,484	43,558
Non-network	7,936,953	3,076,933	1,072,069	1,826,575	877,334	1,040,484	43,558
Network	1,293,187	88,119	132,527	478,009	594,531		

Figure 3.2 presents the consumption mix by customer class. Residential electricity consumption represents 34% of total retail load whereas non-residential is 66%. There are no major differences in the consumption mix between the two years.

Figure 3.2: Percent of Retail Sales by Customer Class, 2019-2020



The monthly retail forecast is developed using historical consumption patterns. **Figures 3.3** and **3.4** show the monthly forecast of electricity consumption by customer class in 2019 and 2020 by peak and off-peak periods. The peak period is defined as Monday–Saturday 6 a.m. to 10 p.m. and the off-peak period is 10 p.m. to 6 a.m. Monday-Saturday, all day Sunday and NERC (North American Electric Reliability Corporation) holidays. Note that only residential customers have a clear seasonal pattern to their consumption, driven by heating and lighting loads.

Figure 3.3: Peak Period Retail Sales by Customer Class, 2019-2020

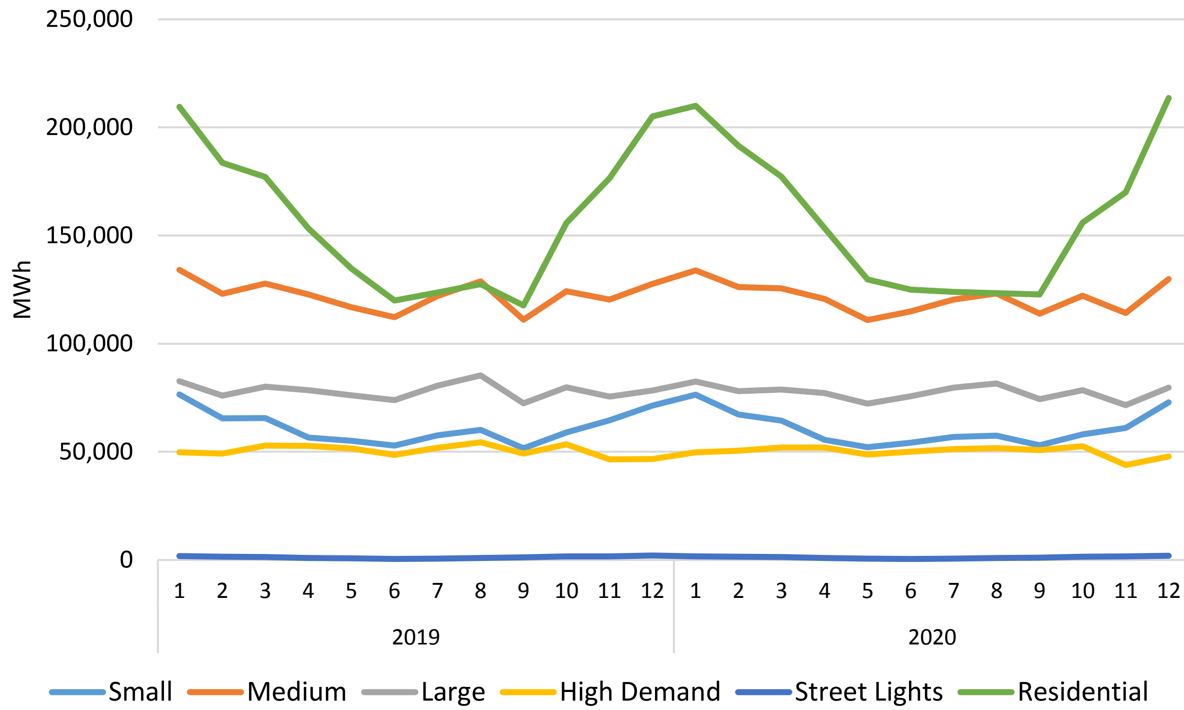
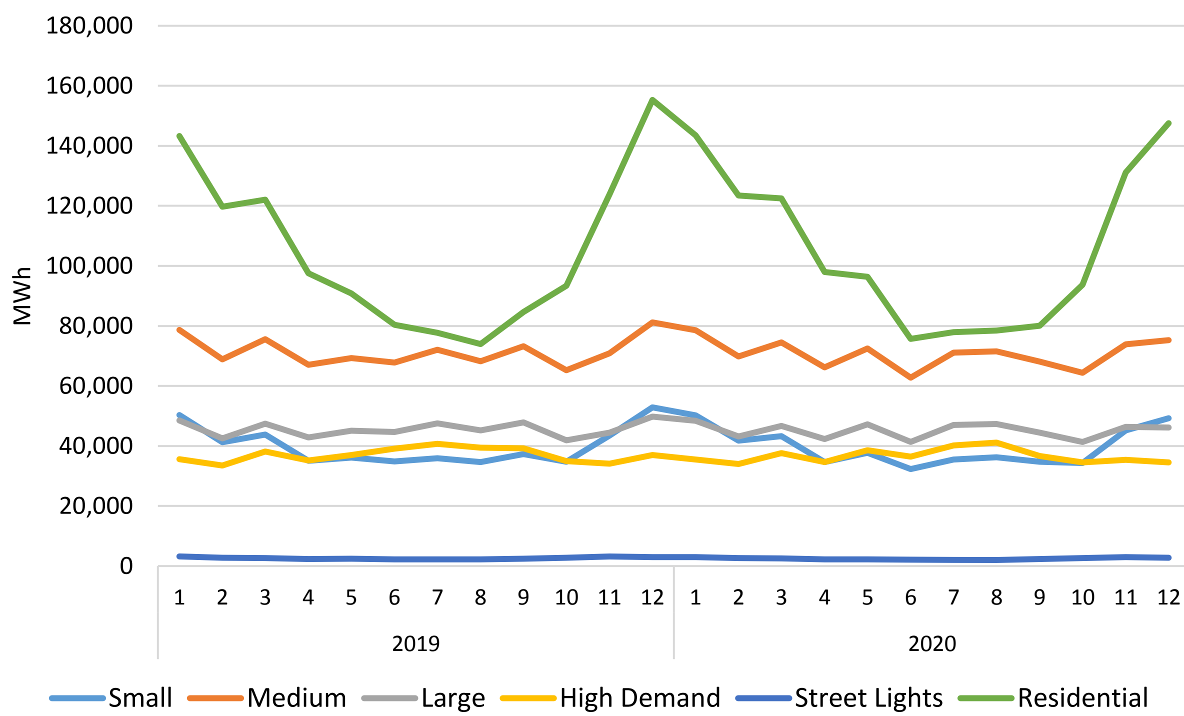


Figure 3.4: Off-Peak Period Retail Sales by Customer Class, 2019-2020



3.2.2. Peak Load Data

Coincident peak load is used to estimate certain distribution costs. Peak load is typically measured in 15-minute intervals. However, since 15-minute interval data for peak load is not available for all customer classes, peak load for rate making purposes is defined as the maximum of either peak or off-peak monthly average consumption. For customer classes the coincident peak load is the peak load during period of total system peak load. **Table 3.3** summarizes average and coincident peak load for 2019 and 2020 by customer class. City Light's system peak occurs in the January peak period.

Table 3.3: Annual Average and Coincident Peak Load

Non-network (Excludes Network Residential & Small that are billed at non-network rates)								
		Total	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Average Annual Load, MW	2019	910.6	349.4	123.7	210.9	101.4	120.0	5.3
	2020	903.6	350.3	122.0	207.9	99.9	118.5	5.0
Load at Coincident Peak*, MW	2019	1,152.5	489.9	163.8	255.8	119.0	119.7	4.4
	2020	1,151.5	490.9	163.4	255.1	118.4	119.6	4.1
Network								
		Total	**Residential**	**Small**	**Medium**	**Large**		
Average Annual Load, MW	2019	148.6	9.9	15.3	55.0	68.4		
	2020	147.2	10.0	15.1	54.4	67.7		
Load at Coincident Peak*, MW	2019	180.5	13.8	20.2	66.7	79.8		
	2020	180.9	14.0	20.2	66.7	80.0		

*Coincident peak occurs during January Peak hours.

3.2.3. System Losses

Energy losses are a natural byproduct of transmission and distribution; therefore, the total amount of energy generated or purchased to meet load is greater than just system load. For the purposes of marginal cost analysis, these losses are estimated as a percentage of load. **Table 3.4** shows system losses for the periods of maximum loads at different points of energy flowing through the system. These loss percentages are used as a basis for the loss percentage that is applied to load for each customer class. The effective loss percentage incurred by each customer class will vary depending on their respective loss percentage and monthly load profile.

Table 3.4: System Losses for Periods of Maximum Loads (% of Load)[2]

Energy Flow Point	Residential	Small and Streetlights	Medium	Large and High
Long-distance transmission from generation point to service area boundary	1.90%	1.90%	1.90%	1.90%
In-service-area transmission from service area boundary to substation	1.14%	1.14%	1.14%	1.14%
Through substation	0.74%	0.74%	0.74%	0.74%
Through 26/13 kV feeders to the high side of the customer transformers	0.82%	0.82%	0.82%	0.82%
Customer transformers and service drop	1.77%	2.31%	0.98%	0.89%

Tables 3.5 and **3.6** present the annual summary of total energy (energy consumption plus losses) required to serve each customer class that is used as a basis to compute the cost of energy.

Table 3.5: 2019 Energy Consumption plus Losses by Customer Class

2019	Total	Residential	Small	Medium	Large	High Demand	Lights
Service Territory	9,714,479	3,293,394	1,279,054	2,435,282	1,556,037	1,101,973	48,738
Non-network	8,352,659	3,202,715	1,138,592	1,931,219	929,422	1,101,973	48,738
Network	1,361,820	90,679	140,462	504,064	626,616		

Table 3.6: 2020 Energy Consumption plus Losses by Customer Class

2020	Total	Residential	Small	Medium	Large	High Demand	Lights
Service Territory	9,660,494	3,311,617	1,265,277	2,408,304	1,538,878	1,090,788	45,629
Non-network	8,307,934	3,219,431	1,126,070	1,908,769	917,246	1,090,788	45,629
Network	1,352,560	92,186	139,207	499,535	621,632		

[2] The energy and demand loss figures apply to the various components of the transmission and distribution system based on a fully converted 26 kV distribution system.

3.2.4. Meter Counts

Tables 3.7 and **3.8** show the projected average number of meters by customer class for 2019 and 2020, respectively. Since new customers (meters) are continuously added to the system while existing customers (meters) are continuously leaving the system, the meter count below is an estimate of the average number of meters for the class during the course of the year. The meter data is based on 2016 billing data, forecasts of new additions and existing customer rate reclassifications.

Table 3.7: 2019 Meter Count

2019	Total	Residential	Small	Medium	Large	High Demand
Service Territory	469,226	420,474	45,333	3,243	167	9
Non-network	441,973	397,159	42,021	2,682	102	9
Network	27,253	23,315	3,312	561	65	0

Table 3.8: 2020 Meter Count

2020	Total	Residential	Small	Medium	Large	High Demand
Service Territory	479,376	430,370	45,568	3,260	169	9
Non-network	450,851	405,846	42,203	2,690	103	9
Network	28,525	24,524	3,365	570	66	0

3.3. Energy Costs

Marginal energy costs are based on the assumption that City Light meets incremental load by purchasing power in the wholesale market and delivering it to its service territory using BPA transmission. The total energy cost for non-network and network is calculated using the formula below:

$$\sum_{i=1}^{12}(Q_{Pi} + L_{Pi}) * (P_{Pi} + EA) + \sum_{i=1}^{12}(Q_{OPi} + L_{OPi}) * (P_{OPi} + EA) + Long\ Distance\ Transmission\ Costs$$

where:

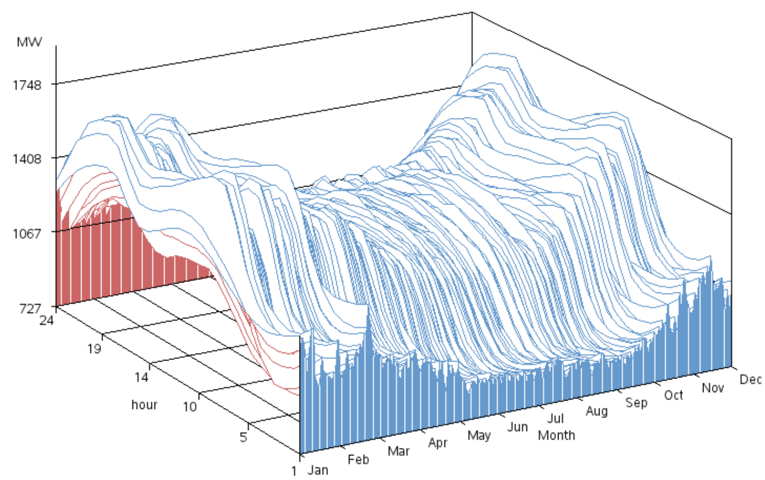
i=1 to 12 and represents a month; P is peak period; OP is off-peak period; Q is energy consumption; L is energy losses; P is wholesale market price; EA is externality adder.

3.3.1. Wholesale Market Electricity Prices

City Light buys and sells power primarily at the Mid-Columbia Trading Hub (Mid-C). Market prices are determined by supply and demand. Supply conditions of many hydroelectric plants in the Mid-C region are dictated to a great extent by rainfall and snow accumulation. Also affecting supply are the many rules and regulations imposed on the operation of hydro plants to protect against flooding and to provide for irrigation, boating and support of fish and wildlife.

The demand is influenced by temperature, time of the day, and day of the week. For example: in cold weather electric heating demand increases, and electricity demand is lower at night when people are asleep and businesses are closed. Also, weekend demand tends to be lower because many businesses close or curtail their operations. **Figure 3.5** shows the variation in electricity consumption by month and hour for a typical City Light year. This consumption pattern is similar across the Pacific Northwest.

Figure 3.5: Seasonality of City Light Electricity Demand in a Typical Year



Electricity prices in the Pacific Northwest tend to increase during winter months due to heating demand, then decrease in the spring during the hydro runoff season when there is an abundance of generation, and then pick up again in the summer as the runoff ends. Off-peak prices are generally lower than peak prices.

Figure 3.6 shows Dow-Jones Mid-C average monthly electricity prices for the period 2008-2017. Market prices declined rapidly following the financial crisis in the fall of 2008 and low natural gas prices have continued to apply downward pressure.

Figure 3.6: Average Monthly Mid-C Electricity Prices, 2008-2017

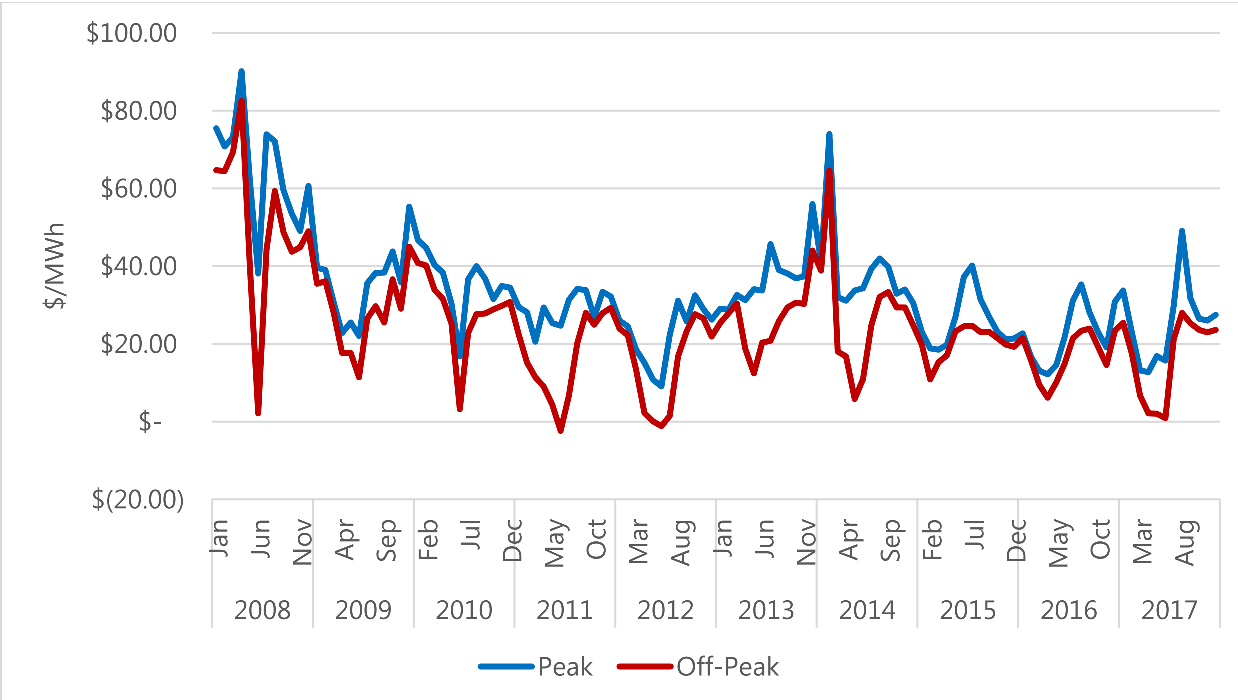
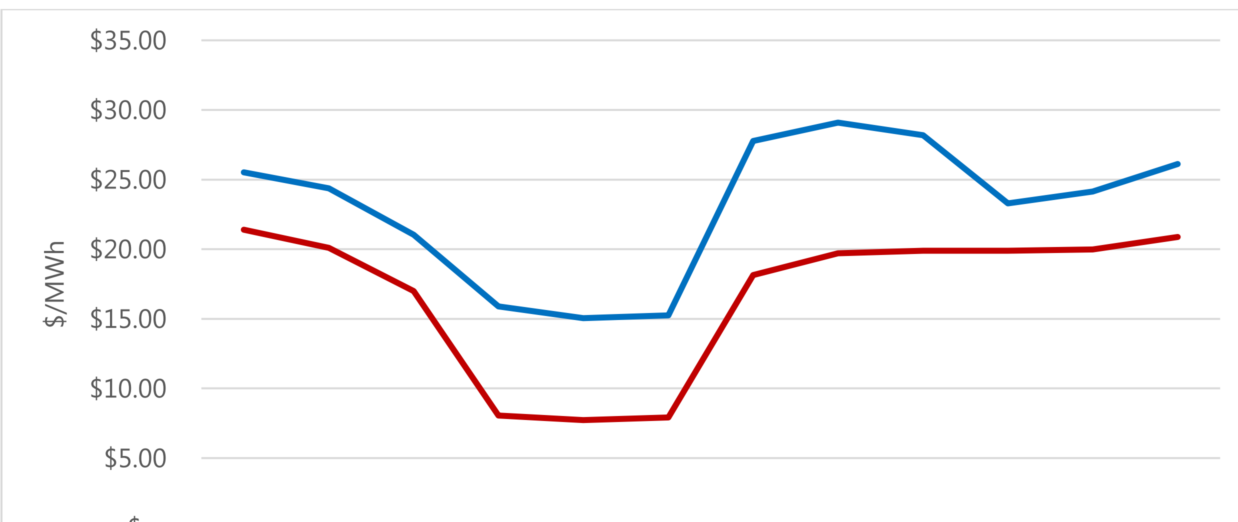
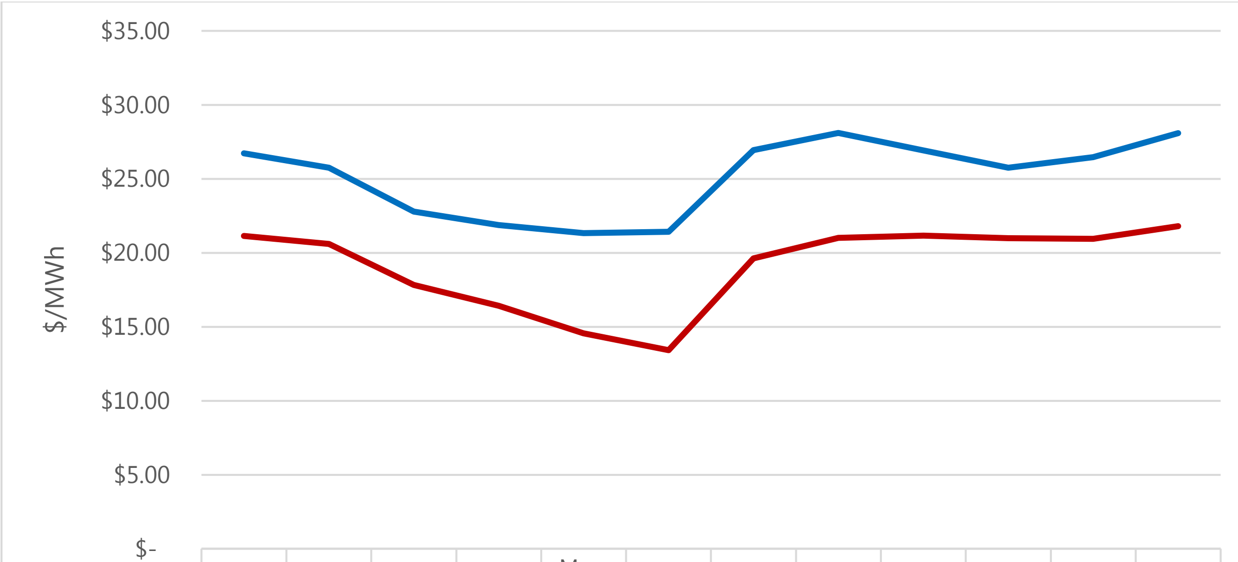


Figure 3.7 presents the forecast of monthly Mid-C electricity prices for 2019 and 2020 as of January 19, 2018. The 2019 and 2020 forecast is based purely on forward wholesale energy prices. Peak and off-peak prices are expected to remain around the same level in 2019 and 2020 with some small differences in the seasonal shaping.

Figure 3.7: Monthly Mid-C Electricity Prices, 2019-2020



	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19
Peak	$25.53	$24.38	$21.04	$15.90	$15.05	$15.25	$27.78	$29.09	$28.18	$23.29	$24.14	$26.11
Off-Peak	$21.40	$20.10	$17.00	$8.05	$7.73	$7.92	$18.14	$19.71	$19.90	$19.88	$19.98	$20.89



	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20
Peak	$26.72	$25.74	$22.79	$21.88	$21.33	$21.42	$26.94	$28.10	$26.91	$25.74	$26.46	$28.08
Off-Peak	$21.14	$20.59	$17.82	$16.41	$14.56	$13.42	$19.63	$21.02	$21.17	$20.99	$20.94	$21.80

3.3.2. Negative Externalities

A byproduct of the production and delivery of electricity are negative consequences such as air, water, and soil pollution, respiratory health problems, reduced visibility, damage to fish and wildlife, and global warming. These externalities impose costs on the environment and society. Therefore, a true cost of electricity includes an estimate of these societal and environmental costs, which we refer to as "environmental externality adders."

The environmental externality adder assumes that carbon dioxide (CO_2) emissions are the primary driver of externality impacts, so the adder is determined by multiplying the amount of CO_2 emitted per MWh by the cost to the environment per unit of CO_2 emitted. The amount of CO_2 emitted in electricity production on the margin was based on an EPA estimate for the Northwest Region. The price of CO_2 emissions for 2019–2020 is based on the City Light forecast of the cost of greenhouse gas offsets for those years.

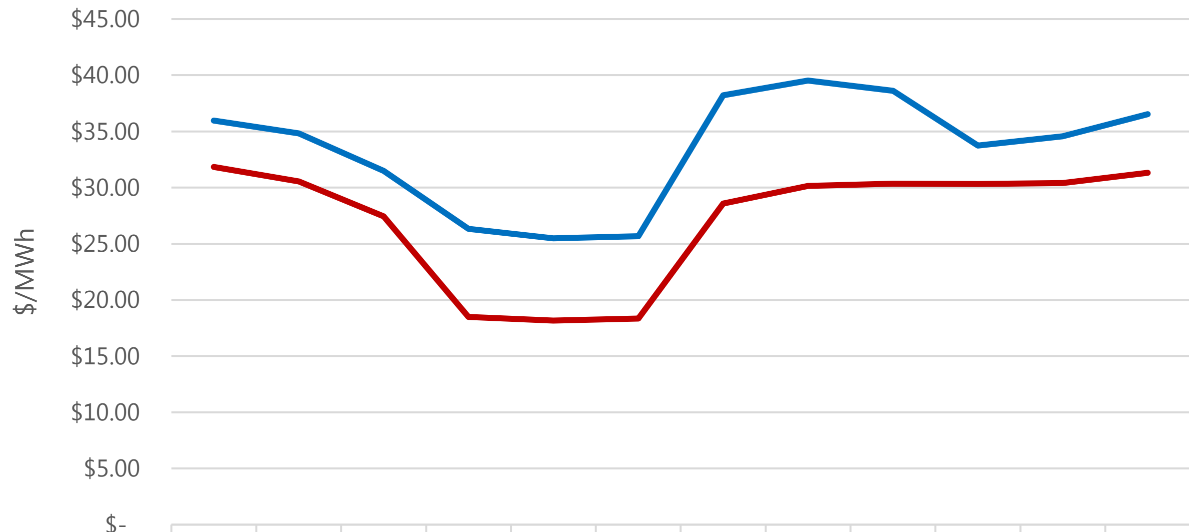
Table 3.9 shows emission factors, price of CO_2 emissions and resulting adders for 2019 and 2020.

Table 3.9: Environmental Externality Adders, 2019-2020

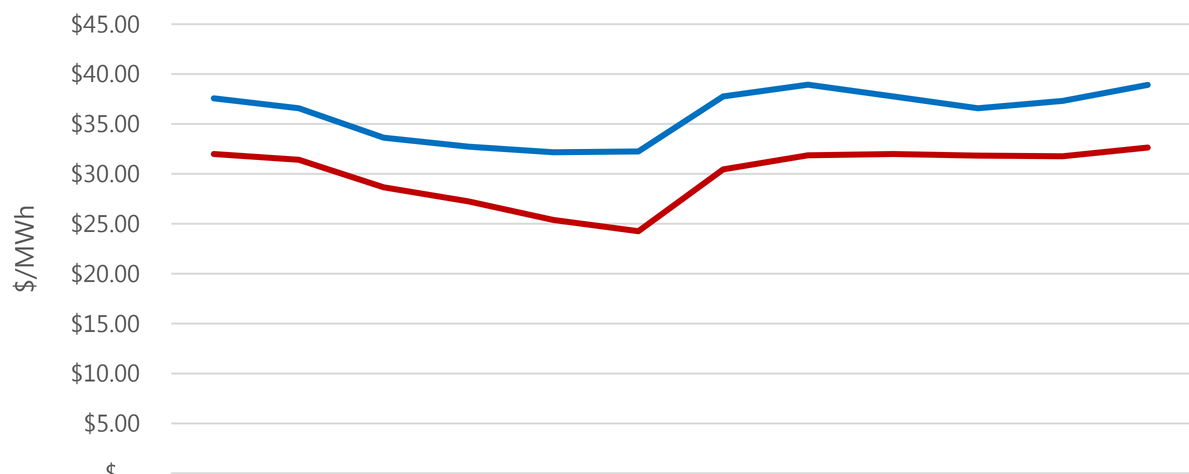
Year	CO_2 Emission Factor (metric tons/MWh)	Price of CO_2 Emissions	Environmental Externality Adder
2019	0.691	$15.10	**$10.43**
2020	0.669	$16.20	**$10.84**

Figure 3.8 presents the forecast of Mid-C monthly electricity prices plus externality costs for 2019 and 2020.

Figure 3.8: Monthly Mid-C Electricity Prices plus Externality Costs, 2019-2020



	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19
Peak	$35.96	$34.81	$31.47	$26.33	$25.48	$25.68	$38.21	$39.52	$38.61	$33.72	$34.57	$36.54
Off-Peak	$31.83	$30.53	$27.43	$18.48	$18.16	$18.35	$28.57	$30.14	$30.33	$30.31	$30.41	$31.32



	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20
Peak	$37.56	$36.58	$33.63	$32.72	$32.17	$32.26	$37.78	$38.94	$37.75	$36.58	$37.30	$38.92
Off-Peak	$31.98	$31.43	$28.66	$27.25	$25.40	$24.26	$30.47	$31.86	$32.01	$31.83	$31.78	$32.64

3.3.3. Energy Consumption plus Losses Costs

Tables 3.10 and **3.11** present total costs of energy consumption plus losses by customer class for 2019 and 2020. These costs were calculated for each customer class in non-network and network categories by multiplying total monthly peak and off-peak load plus losses by the associated projected monthly market price plus externality adder, and then summing results for each year.

Table 3.10: Energy Consumption plus Losses Costs in 2019

2019	Total	Residential	Small	Medium	Large	High Demand	Lights
Service Territory	$302,816,093	$102,835,880	$39,972,982	$76,095,659	$48,574,864	$33,891,488	$1,445,221
Non-network	$260,282,186	$100,003,943	$35,583,115	$60,344,609	$29,013,810	$33,891,488	$1,445,221
Network	$42,533,907	$2,831,937	$4,389,866	$15,751,050	$19,561,054		

Table 3.11: Energy Consumption plus Losses Costs in 2020

2020	Total	Residential	Small	Medium	Large	High Demand	Lights
Service Territory	$326,295,892	$111,912,812	$42,774,532	$81,568,592	$52,090,774	$36,481,098	$1,468,084
Non-network	$280,512,020	$108,797,121	$38,068,349	$64,649,125	$31,048,243	$36,481,098	$1,468,084
Network	$45,783,872	$3,115,691	$4,706,183	$16,919,466	$21,042,531		

3.3.4. Long-Distance Transmission Costs

All City Light energy generation occurs outside the service territory and requires long-distance transmission to transmit power to end users. In practice, City Light purchases the bulk of its transmission via long-term contracts. However, for the purposes of marginal cost analysis, transmission costs are valued a single year at a time, with the amount purchased sized to serve the peak demand each year.

The amount of transmission capacity needed is estimated by multiplying annual average load by 170%, a percentage derived from historical load data that approximates the relationship between average and peak system load. The annual average load (this can be found in **Table 3.3** by adding network and non-network totals) for the service territory is 1,059 MW for 2019 and 1,051 MW for 2020. Transmission capacity required therefore is 1,800 MW and 1,787 MW for 2019 and 2020 respectively.

The price for BPA transmission services is $1,875/MW per month in 2019 and $1,958/MW per month in 2020. The annual long-distance transmission costs are $40,508,998 for 2019 and $41,971,915 for 2020, which must be allocated among customer classes.

An estimate of the quantity of transmission services needed to serve each class on its own was developed as if it were the only class being served.[3] The results were summed over all classes. Shares of the cost of transmission from this set of calculations were then used to allocate the costs of transmission from the analysis of the actual system load. This process yields a fair apportionment of the net cost of transmission services while preserving a useful estimate of the marginal value of transmission services for each customer class. **Tables 3.12** and **3.13** present long-distance transmission costs by customer class in 2019 and 2020.

Table 3.12: Long-Distance Transmission Costs in 2019

2019	Total	Residential	Small	Medium	Large	High Demand	Lights
Service Territory	$40,508,998	$13,741,213	$5,313,208	$10,169,000	$6,494,175	$4,588,265	$203,138
Non-network	$34,827,433	$13,362,811	$4,729,741	$8,064,240	$3,879,240	$4,588,265	$203,138
Network	$5,681,564	$378,402	$583,467	$2,104,760	$2,614,935		

Table 3.13: Long-Distance Transmission Costs in 2020

2020	Total	Residential	Small	Medium	Large	High Demand	Lights
Service Territory	$41,971,915	$14,392,340	$5,477,622	$10,479,561	$6,692,963	$4,731,361	$198,068
Non-network	$36,091,449	$13,991,637	$4,874,985	$8,305,928	$3,989,471	$4,731,361	$198,068
Network	$5,880,466	$400,703	$602,637	$2,173,634	$2,703,492		

City Light does earn a small amount of revenue seasonally from sales of surplus transmission capacity. However, in this analysis the long-distance transmission costs are allocated gross of this revenue.

3.3.5. Total Energy Costs

The total energy cost is the sum of energy consumption plus losses costs and costs of long-distance transmission derived in sections 3.3.3 and 3.3.4, respectively. **Tables 3.14** and **3.15** show total energy costs by customer class for 2019 and 2020. These costs are used to derive energy allocation factors by customer class summarized in Section 3.6.

[3] Following the procedure for calculating the amount of capacity for the total system, the amount of capacity that theoretically would be purchased for each class would be 170% of the average load for each class. Therefore, each class is allocated the same percentage of the total system transmission costs as its share of load.

Table 3.14: Total Energy Costs in 2019

2019	Total	Residential	Small	Medium	Large	High Demand	Lights
Service Territory	$343,325,091	$116,577,092	$45,286,189	$86,264,659	$55,069,038	$38,479,753	$1,648,359
Non-network	$295,109,620	$113,366,753	$40,312,856	$68,408,849	$32,893,050	$38,479,753	$1,648,359
Network	$48,215,471	$3,210,339	$4,973,333	$17,855,810	$22,175,989		

Table 3.15: Total Energy Costs in 2020

2020	Total	Residential	Small	Medium	Large	High Demand	Lights
Service Territory	$368,267,807	$126,305,152	$48,252,154	$92,048,153	$58,783,738	$41,212,458	$1,666,151
Non-network	$316,603,469	$122,788,758	$42,943,334	$72,955,053	$35,037,714	$41,212,458	$1,666,151
Network	$51,664,338	$3,516,394	$5,308,820	$19,093,100	$23,746,023		

3.4 Distribution Costs

Total distribution costs are composed of the marginal costs of:

1. In-service-area transmission costs;
2. Substation costs;
3. Wires and related equipment costs;
4. Customer transformer costs;
5. Streetlights costs (from Chapter 2, Table 2.2, Functionalized Revenue Requirements).

These costs cover purchase, maintenance and replacement of the equipment and facilities necessary to provide distribution service to existing and new customers. Costs by customer class are developed in three steps. First, estimates of annualized capital costs and annual operations and maintenance (O&M) costs per MW (per meter for service drops) for the indicated component are developed. Second, these per unit costs are multiplied by the appropriate coincident peak load (or number of meters) for each class. Third, the sum of these costs is computed for each class.

Marginal costs of distribution equipment and services use an estimate of how much it would cost to replace this equipment today, not how much it cost originally. These estimates are obtained from a combination of engineering estimates of recent and ongoing projects, FERC accounts, and current catalogue costs of specific equipment as well as standardized work practices.

3.4.1 In-Service-Area Transmission

In-service-area transmission costs consist of the O&M and capital costs associated with the delivery of energy through high voltage lines from the service territory boundary to substations.

In-Service-Area Transmission Capital Costs
Table 3.16 presents the capital cost required to replace all in-service-area transmission lines. Per-mile cost estimates are developed by City Light engineers using costs of recent actual replacements of major in-service-area transmission lines. There were no major changes from the previous cost of service study; dollar values have only been updated to reflect inflation. These costs are multiplied by the 230.4 miles of line estimated within the service territory. Appendix A indicates that the expected service life for this type of equipment is 43 years with a corresponding annualization factor of 0.04170. The total equipment cost is multiplied by the annualization factor and divided by total in-service-area capacity to obtain the capital cost per MW.

The capacity must also cover 2.7% losses on the system, the sum of assumed transmission losses through the service territory (1.14%), substations (0.74%) and feeders (0.82%), as shown in **Table 3.4** in section 3.2. The cost per MW is adjusted for losses by dividing through by (1-loss factor) as shown in **Table 3.16**.

Table 3.16: In-Service-Area Transmission Capital Costs

	Miles	2016 $Millions/Mile	Total 2016$Millions
115 kV			
Overhead (OH)	97.2	$3.3	$318.5
Underground (UG)	21.1	10.9	230.4
Subtotal	118.3	4.6	548.9
230 kV			
Overhead (OH)	92.9	$3.8	355.0
Underground (UG)	19.2	13.1	250.9
Subtotal	112.0	5.4	605.9
Total	**230.4**	**$5.0**	**$1,154.8**
Annualization factor			0.04170
In-Service-Area Capacity (MW)			2,892
Loss Factor			2.7%
Annual Capital Cost $2016 /per MW			**$17,112**

In-Service-Area Transmission O&M Costs

In-service-area transmission O&M costs are based on a three-year average of actual costs, adjusted for inflation. **Table 3.17** presents the costs associated with in-service-area transmission by FERC account for 2014 through 2016. FERC names are listed as they appear in the system; some line items may look abbreviated or truncated. Dividing total cost by in-service-area capacity produces annual O&M cost per MW.

Table 3.17: In-Service-Area Transmission O&M Costs for 2014-2016

FERC Code	FERC #	2014	2015	2016
OS&E-INSIDE SEATTLE	56016	$78	$17,151	$5,041
O-STATION EXP, INSIDE SEATTLE	56216	28,854	28,080	45,595
OP OV LINE EXP-INSIDE SEATTLE	56316	0	0	0
OP UN LINE EXP-INSIDE SEATTLE	56416	15,150	0	0
OP MISC L EXP-INSIDE SEATTLE	56616	27,864	29,811	7,917
MS&E-INSIDE SEATTLE	56816	13	0	0
MAINT TRANS ST-INSIDE SEATTLE	56916	2,945	3,355	2,432
MAINT RELAY SE-INSIDE SEATTLE	57016	25,547	11,473	421
MAINT STAT EQ-INSIDE SEATTLE	57026	722,107	494,604	683,303
ROADS & TRAILS-INSIDE SEATTLE	57116	23,117	20,938	8,379
TOWERS & POLES-INSIDE SEATTLE	57126	112,243	24,354	14,263
M O/H TRANS CO-INSIDE SEATTLE	57136	0	0	0
CLR TREE&BRSH-INSIDE SEATTLE	57146	221,468	217,649	180,542
MAINT O/H ENG-INSIDE SEATTLE	57156	0	0	0
U/G NON ELEC EQ-INSIDE SEATTLE	57216	8,164	1,971	1,223
U/G ELEC EQ-INSIDE SEATTLE	57226	0	1,251	0
U/G ELEC ACCESS-INSIDE SEATTLE	57236	4,930	0	1,348
U/G MAINT ENG-INSIDE SEATTLE	57246	0	0	0
MISC TRANS PLA-INSIDE SEATTLE	57316	148	3,757	555
SUBTOTAL (excl 56016 - a supervisory cost)		1,192,551	837,243	945,977
Subtotal in $2016		**$1,230,828**	**$856,351**	**$945,977**
$Three Year Average				1,011,052
In-Service-Area Capacity (MW)				2,892
Annual O&M, $2016/MW				**$350**

Total In-Service-Area Transmission Costs by Customer Class

Tables 3.18 and **3.19** present total in-service-area transmission costs for 2019 and 2020, respectively. The costs are calculated using the following formula:

$$\frac{(Capital\ Costs/MW + O\&M\ Costs/MW) * Inflation * Class\ Coincident\ Peak\ Load * ISA\ Capacity}{Total\ Service\ Territory\ Peak\ Load}$$

Note that the $/MW are based on a cost per unit of total capacity that exceeds the load placed on in-service-area transmission. Thus, to reflect costs for actual in-service-area transmission usage by a class, the $/MW cost of total capacity is multiplied by the class coincident peak load and that result is multiplied by the total in-service-area transmission capacity divided by the system peak load.

Table 3.18: 2019 In-Service-Area Transmission Costs

Capital Costs $2016/MW		$17,112					
O&M Costs $2016/MW		$350					
In-Service-Area Transmission Capacity MW		2,892					
2019 Coincident Peak Load (MW)							
	Total	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Non-network	1,152.5	489.9	163.8	255.8	119.0	119.7	4.4
Network	180.5	13.8	20.2	66.7	79.8		
Service Territory	1,333.0						
2019 In-Service-Area Transmission Costs				**$2019 inflation adjustment =**			**1.07415**
	Total	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Non-network	$46,897,888	$19,934,286	$6,663,801	$10,408,787	$4,840,920	$4,872,954	$177,140
Network	$7,345,684	$562,384	$821,503	$2,714,038	$3,247,759		
Service Territory	$54,243,572	$20,496,670	$7,485,304	$13,122,825	$8,088,679	$4,872,954	$177,140

Table 3.19: 2020 In-Service-Area Transmission Costs

Capital Costs $2016/MW		$17,112					
O&M Costs $2016/MW		$350					
In-Service-Area Transmission Capacity MW		2,892					
2020 Coincident Peak Load (MW)							
	Total	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Non-network	1,151.5	490.9	163.4	255.1	118.4	119.6	4.1
Network	180.9	14.0	20.2	66.7	80.0		
Service Territory	1,332.4						
2020 In-Service-Area Transmission Costs				**$2020 inflation adjustment =**			**1.10146**
	Total	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Non-network	$48,069,792	$20,492,021	$6,822,028	$10,651,085	$4,942,131	$4,992,965	$169,563
Network	$7,552,851	$584,719	$842,758	$2,784,623	$3,340,751		
Service Territory	$55,622,644	$21,076,740	$7,664,786	$13,435,708	$8,282,882	$4,992,965	$169,563

3.4.2 Substations

Substations transform high voltage power delivered by in-service-area transmission lines to lower voltages for distribution feeder lines. Whereas there are no differences among in-service-area transmission costs per MW for customer classes inside and outside the network, there are some differences in the capital costs of substations for non-network and network customers.

Substation Capital Costs

City Light is currently building a 180 MW substation in the Denny Triangle area. Although it is actually being built only to support 13 kV network feeders, it was originally designed also to support 26 kV non-network feeders. Therefore, the engineering estimates and costs developed for this project are being used as the source of the initial capital cost estimates for both network and non-network substations. **Table 3.20** presents total costs of replacement for a substation and associated annual capital costs per MW.

Table 3.20: Substation Capital Costs

	Network	Non-network
Total Costs of Replacement, $2016	**$70,866,594**	**$63,303,589**
Capacity (MW)	180	180
Annualization Factor	0.04384	0.04384
Loss Factor	1.56%	1.56%
Annual Capital Costs $2016/ MW	**$17,535**	**$15,664**

Annual substation capital costs per MW is derived by dividing the total capital cost by the substation capacity, multiplying this by the annualization factor, and lastly dividing the annualized capital cost per MW by (1-loss factor).

Substation O&M Costs

Table 3.21 presents data on the annual O&M costs associated with the system's substations by FERC account, using a three-year average adjusted for inflation. Substation operations and maintenance costs are adjusted for the age of facilities using an adjustment factor of 0.673, the derivation of which is described next.

Since reported O&M expenses cover all substations of all ages there is a concern that the average cost per MW derived from these data would not adequately predict the cost for servicing a new marginal substation. A relationship between age of a substation and the amount of maintenance needed was established by regressing the labor costs on the age of substation as shown in the equation below:

$$Labor\ Costs\ (\$/MW) = a + b * Age\ of\ Substation + error\ term$$

In order to adjust the substation maintenance cost from historical data to reflect the annualized value of the maintenance costs for a marginal substation, we computed the ratio between the projected labor cost at the average age of City Light's substations (30.5 years) and the annualized cost for a new substation over its economic life, which was found to be equivalent to the projected labor costs at age 14 years. Using the estimated coefficients from the equation above this ratio was found to be 1.485. The age adjustment factor is the reciprocal of this ratio and is 0.673.

The three-year average is divided by the substation capacity to obtain the annual O&M per MW.

Table 3.21: Substation O&M Costs

		FERC #	2014	2015	2016
1	Load Dispatching	58101	2,808,008	2,947,834	3,034,714
2	Distribution Substation Equipment	58201	3,859,341	4,002,489	4,210,794
	Maintenance of Station Equipment	59201	1,535,176	918,068	1,179,460
	Age Adjustment Factor		0.673	0.673	0.673
3	Maintenance of Station Equipment, Adj.		1,033,174	617,860	793,777
4	Maintenance of Distribution Structures	59101	1,584,423	1,362,073	1,079,874
5	Maintenance of Station Relay	59205	14,939	4,857	29,552
	Total (1+2+3+4+5)		9,284,945	8,930,256	9,119,159
	Total in $2016		**$9,582,965**	**$9,134,068**	**$9,119,159**
	Three year average				$9,278,7311
	Substation Capacity (MW)	2,458			
	Annual O&M, $2016/MW				**$3,775**

Total Substation Costs

Total substation costs for 2019 and 2020 are shown in **Tables 3.22** and **3.23**. These calculations are similar to total in-service-area transmission costs and are based on the following formula:

$$\frac{(Capital\ Costs/MW + O\&M\ Costs/MW) * Inflation * Class\ Coincident\ Peak\ Load * Subst\ Capacity}{Total\ Service\ Territory\ Peak\ Load}$$

This computation is repeated for network and non-network capital costs.

Similar to the calculations for in-service-area transmission costs, $/MW costs are based on the theoretical total capacity, which exceeds the load actually placed on substations. Thus, to get costs for actual substation usage by a particular class, the $/MW cost of total capacity is multiplied by the class coincident peak load and that result is multiplied by the substation capacity divided by the system peak load.

Table 3.22: 2019 Substation Costs

Network Capital Costs $2016/MW				$17,535			
Non-network Capital Costs $2016/MW				$15,664			
O&M Costs $2016/MW				$3,775			
Total Substation Capacity MW				2,458			
2019 Coincident Peak Load (MW)							
	Total	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Non-network	1,152.5	489.9	163.8	255.8	119.0	119.7	4.4
Network	180.5	13.8	20.2	66.7	79.8		
Service Territory	1,333.0						
2019 Substation Costs					$2019 inflation adjustment =		1.07415
	Total	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Non-network	$44,372,647	$18,860,914	$6,304,985	$9,848,320	$4,580,258	$4,610,567	$167,601
Network	$7,619,249	$583,328	$852,097	$2,815,113	$3,368,710		
Service Territory	$51,991,895	$19,444,242	$7,157,082	$12,663,434	$7,948,969	$4,610,567	$167,601

Table 3.23: 2020 Substation Costs

Network Capital Costs $2016/MW				$17,535			
Non-network Capital Costs $2016/MW				$15,664			
O&M Costs $2016/MW				$3,775			
Total Substation Capacity MW				2,458			
2020 Coincident Peak Load (MW)							
	Total	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Non-network	1,151.5	490.9	163.4	255.1	118.4	119.6	4.1
Network	180.9	14.0	20.2	66.7	80.0		
Service Territory	1,332.4						
2020 Substation Costs					$2020 inflation adjustment =		1.10146
	Total	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Non-network	$45,481,449	$19,388,617	$6,454,692	$10,077,571	$4,676,020	$4,724,116	$160,433
Network	$7,834,131	$606,495	$874,144	$2,888,327	$3,465,166		
Service Territory	$53,315,581	$19,995,112	$7,328,836	$12,965,898	$8,141,186	$4,724,116	$160,433

3.4.3. Wires and Related Equipment

Wires and related equipment transport power over 26 kV lines (for non-network customers) or 13 kV lines (for network customers) from substations to the customer transformer, and from the customer transformer to the meter through a line called the service drop. Revenue requirements for wires and related equipment are assigned directly to non-network and network customers in the functionalization of revenue requirements (see Section 2).

Wires and Related Equipment Capital Costs

Tables 3.24 and **3.25** present the costs associated with wires and related equipment for non-network and network portions of the system, respectively. The calculation of per unit capital costs is similar to that for substations: the total capital cost for non-network/network is divided by capacity to obtain the cost per MW, which is then multiplied by the annualization factor and adjusted for losses.

Table 3.24: Non-network Wires and Related Equipment Capital Cost

Item	Labor Cost	Unit Material Cost	Total Labor & Material Cost	System Quantity	Total Cost
Down guy anchor	$602	$295	$897	20,541	$18,434,136
Pipe brace anchor	905	460	1,365	6,299	8,596,794
Push brace	1,399	1,480	2,879	23	66,208
Circuit Breaker	3,259	668	3,927	173	679,329
Sectionalizers	605	759	1,363	128	174,471
Cutout w/ limiter	605	759	1,363	767	1,045,464
Cutout w/o limiter	605	279	883	4,211	3,719,559
0'-29' Concrete, Laminated, Wood poles	1,399	504	1,902	3,482	6,623,834
30'-40' Concrete, Laminated, Wood poles	1,399	799	2,198	26,476	58,189,419
0'-40' Fiber Glass, and Plastic poles	2,599	4,524	7,123	1,118	7,963,272
40'-50' Fiber Glass poles	2,599	5,024	7,623	4	30,494
61'-69 Fiber Glass poles	2,599	6,955	9,554	1	9,554
40'-45' Concrete, Laminated, Wood poles	1,399	1,131	2,530	14,986	37,907,652
45'-50' Concrete, Laminated, Wood poles	1,399	1,480	2,879	36,372	104,701,042
51'-55' Concrete, Laminated, Wood poles	1,399	1,746	3,145	7,160	22,518,131
56'-60' Concrete, Laminated, Wood poles	1,699	2,019	3,718	3,141	11,676,708
61'-69' Concrete, Laminated, Wood poles	1,699	2,320	4,019	1,370	5,506,190
71'-80' Concrete, Laminated, Wood poles	1,699	3,391	5,089	1,181	6,010,698
#4 bare copper wire/ft, 1 phase	36	3	39	4,161,703	164,251,724
#4 bare copper wire/ft, 3 phase	57	5	62	1,286,519	80,228,964
397 ACSR, 3 phase, 600 amp	69	6	76	2,665,182	201,447,500
954 ACSR, 3 phase, 1200 amp	90	13	103	698,418	71,746,294
954 ACSR, 34 kV	90	16	107	20,625	2,197,077
1/0 triplex; inc open 2-#2 & 1-#4	9	1	10	5,362,769	55,985,573
1/0 quadplex	9	2	11	92,524	1,059,245
600 amp horizontal LB switch	6,046	9,000	15,046	961	14,458,887
600 amp riser LB switch	7,322	12,185	19,507	393	7,666,149
1200 amp horizontal LB switch	6,348	12,966	19,313	358	6,914,198
1200 amp riser LB switch	10,720	15,442	26,162	142	3,715,054
Handholes, ave 233 & 444	5,611	4,932	10,544	12,002	126,545,332
Manholes, 712	29,700	30,422	60,123	161	9,679,795
Vaults, ave, 577, 612, 814 & 818	37,552	36,010	73,563	9,780	719,444,424
Pads, ave	4,331	3,257	7,588	1,330	10,092,268
single 1/0 27 kV UG inc duct, trench	425	348	773	981,966	759,507,768
three 1/0 27 kV UG inc duct, trench	425	352	778	1,215,971	945,760,283
1000 kCM UG inc duct, trench	556	483	1,039	547,834	569,179,425
2-1000kCM UG inc duct, trench	577	569	1,146	152,238	174,485,060
2-way 600 amp vista w/ local control	31,645	80,254	111,899	53	5,930,648
3-way 600 amp vista w/ local control	32,751	45,272	78,024	10	780,236

Table 3.24: Non-network Wires and Related Equipment Capital Cost (continued, page 2)

Item	Labor Cost	Unit Material Cost	Total Labor & Material Cost	System Quantity	Total Cost
3-way 600 & 900 amp vista w/ provision for remote control	42,020	45,272	87,293	5	436,464
4-way 600 & 900 amp vista w/ local control	41,402	56,127	97,530	12	1,170,355
4-way 600 amp vista w/ provision for remote control	50,545	56,127	106,672	3	320,016
5-way 600 amp vista w/ local control	38,004	61,051	99,055	20	1,981,100
5-way 600 amp vista w/ provision for remote control	47,273	169,171	216,444	9	1,947,994
6-way 600 amp vista w/ local control	47,878	52,282	100,160	19	1,903,032
6-way 600 & 900 amp vista w/ provision for remote control	57,146	52,282	109,428	1	109,428
PMH 9 switch	27,808	36,296	64,103	70	4,487,243
PMH10 switch	30,897	35,409	66,307	10	663,066
PMH11 switch	29,352	35,853	65,205	6	391,230
PMH12 switch	26,263	38,093	64,356	28	1,801,958
600 amp metal clad switch gear bay	7,724	120,737	128,462	55	7,065,391
1200 amp metal clad switch gear bay	15,449	181,106	196,555	5	982,773
Terminators	4,160	3,976	8,137	3,681	29,951,038
1-3 Pos LB J-Box	7,415	735	8,150	913	7,441,050
3-3 Pos LB J-Box	5,253	1,899	7,152	959	6,858,811
1-4 Pos LB J-Box	7,415	860	8,275	374	3,094,826
3-4 Pos LB J-Box	5,253	2,471	7,724	1,090	8,419,195
1-5 Pos LB J-Box	8,651	2,481	11,132	17	189,241
3-5 Pos LB J-Box	6,797	7,137	13,934	188	2,619,666
Subtotal					**$4,306,762,737**

First Hill and U District Network Costs	Per Unit Cost, $2016	# of Units	Total Cost, $2016
System Man Hole/Vaults	$291,417	328	$95,584,820
System Hand Holes	116,777	57	6,656,304
System Ducts	2,630	115,166	302,900,233
System Primary Feeder Cable	18,017	539	9,710,526
System Secondary Cables	10,655	480	5,114,192
Service Cables	10,655	213	2,268,830
Cable Limiters	105	10,129	1,065,619
Secondary Bus Bars	4,952	355	1,757,955
Subtotal			**$425,058,480**
Total in $2016			**$4,731,821,217**
Total Capacity MW			5,603
Annualization factor			0.0490466
Loss Factor			0.82%
Annual Capital Costs $2016/ MW			**$41,762**

Table 3.25: Network Wires and Related Equipment Capital Cost

	Per Unit Cost	# of Units	Total Cost
System Man Hole/Vaults	291,417	1,414	412,063,829
System Hand Holes	116,777	478	55,819,532
System Ducts	2,630	463,519	1,219,109,920
System Primary Feeder Cable	18,017	4,932	88,860,804
System Secondary Cables	10,655	1,941	20,677,896
Service Cables	10,655	484	5,158,353
Cable Limiters	105	43,179	4,542,636
Secondary Bus Bars	4,952	1,101	5,452,138
Total in $2016			**$1,811,685,107**
Total Capacity MW			660
Annualization factor			0.0490466
Loss Factor			0.82%
Annual Capital Costs $2016/ MW			**$135,745**

Wires and Related Equipment O&M Costs

Table 3.26 presents the annual O&M costs for non-network service for the years 2014 through 2016, along with the three-year average. The costs for non-network service include service for First Hill and the University District, which have some characteristics of network service but are considered non-network for the purposes of rate making. In FERC records, O&M costs for First Hill and the University District are combined with downtown network costs and must be divided using proportion of total network load. In 2016, downtown network load comprised 85% of total network load, while First Hill and the University District comprised the remaining 15%. Thus, the O&M costs of First Hill and the University District areas are estimated to be 15% of total network O&M costs.

Table 3.27 presents the annual O&M costs for network service for the years 2014 through 2016, as well as the three-year average. As mentioned above, the load in the downtown network accounted for 85% of the total of all network loads in 2016 so the total network cost data were adjusted by this percentage to estimate the annual O&M costs for the downtown network. To get annual O&M costs per MW the three-year average total non-network or network annual costs in $2016 are divided by the non-network or network capacity.

Table 3.26: Non-network O&M Costs-Wires and Related Equipment

FERC Code	FERC #	2014	2015	2016
Non-network Costs				
INSP TEST & PATROL OH DIST LIN	58352	$544,880	$399,755	$624,899
OH LINE ENGR EXP	58359	276,067	298,961	275,163
CLEAR TREES & TRIM BRUSH OH LI	59350	4,921,017	6,741,799	5,488,157
MAINT POLES CONDCTRS & SERVICE	59352	5,850,882	9,903,505	9,085,564
INSP & TEST UG DIST	58462	1,521,087	1,532,756	1,854,824
UG ENGR LINE EXP	58469	103,755	158,575	403,500
MAINT NON-ELECT UG EQUIP	59460	582,898	761,771	1,364,784
MAINT ELECT UG EQUIP	59462	4,251,254	4,724,579	3,618,903
Subtotal		**$18,051,840**	**$24,521,700**	**$22,715,794**
Network Costs (First Hill and U District 15.0%)				
INSPECT & TEST NETWORK UG DIST	58442	$447,221	$206,878	$279,016
MAINT NETWORK UG LINES	59440	8,964	0	0
MAINT NETWORK UG EQUIP	59442	999,493	2,489,574	1,261,370
MISC NETWK UG DIST SYS EXP	58841	3,617	565	145
Subtotal		**$1,459,296**	**$2,697,017**	**$1,540,530**
Subtotal x 15.0%	**15%**	**$218,894**	**$404,553**	**$231,080**
11Total Non-network Rate Classes O&M Expenses		**$18,270,734**	**$24,926,253**	**$22,946,874**
Totals in $2016		**$18,857,172**	**$25,495,134**	**$22,946,874**
Three Year Average				$22,433,060
Total Capacity MW				5,603
Annual O&M Costs $2016/ MW				**$4,004**

Table 3.27: Network O&M Costs-Wires and Related Equipment

FERC Code	FERC #	2014	2015	2016
Network Costs (Downtown Network 85.0%)				
INSPECT & TEST NETWORK UG DIST	58442	$447,221	$206,878	$279,016
MAINT NETWORK UG LINES	59440	8,964	0	0
MAINT NETWORK UG EQUIP	59442	999,493	2,489,574	1,261,370
MISC NETWK UG DIST SYS EXP	58841	3,617	565	145
Subtotal		$1,459,296	$2,697,017	$1,540,530
Subtotal x 85.0%	**85%**	**$1,240,401**	**$2,292,465**	**$1,309,451**
Total in $2016		**$1,280,215**	**$2,344,784**	**$1,309,451**
Three Year Average				$1,644,817
Total Capacity MW				660
Annual O&M Costs $2016/MW				**$2,492**

Service Drop Capital and O&M Costs

Service drops refer to the wires that lead from a customer transformer to the meter. Service drop capital costs vary by the configuration and size of wires (e.g., one or three phase service, ampere rating of the wires) and are computed per meter, not per MW. **Table 3.28** presents the derivation of capital and O&M costs per meter. **Table 3.29** shows meter count projections for 2019 and 2020 and the derivation for those years of the total capital plus O&M costs for service drops.

Table 3.28: Service Drop Capital and O&M Costs per Meter

	Residential	Small	Medium	Large	High Demand
Non-network					
Annualized Capital Cost	$28,239,250	$3,077,145	$716,132	$351,584	$146,832
Number of Meters	367,813	41,210	2,656	98	10
Capital Cost per Meter	76.78	74.67	269.62	3,581.60	14,217.05
O&M Cost per Meter	7.68	7.68	7.68	7.68	7.68
$2016/Meter	**$84.45**	**$82.35**	**$277.29**	**$3,589.28**	**$14,224.72**
Network					
Annualized Capital Cost	$2,019,807	$368,703	$140,256	$1,081,366	
Number of Meters	20,113	3,189	528	61	
Capital Cost per Meter	100.42	115.60	265.86	17,865.35	
O&M Cost per Meter	7.68	7.68	7.68	7.68	
$2016/Meter	**$108.10**	**$123.28**	**$273.54**	**$17,873.03**	

Table 3.29: 2019 and 2020 Service Drop Costs

		Residential	Small	Medium	Large	High Demand
Non-network Costs $2016/Meter		$84.45	$82.35	$277.29	$3,589.28	$14,224.72
Network Costs $2016/Meter		$108.10	$123.28	$273.54	$17,873.03	
2019 Costs for Service Drops				**$2019 inflation adjustment =**		**1.07415**
Non-network	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**
Number of Meters	441,973	397,159	42,021	2,682	102	9
$2019 Total	**$41,075,414**	**$36,028,874**	**$3,716,924**	**$798,847**	**$393,252**	**$137,515**
Network	**Total**	**Residential**	**Small**	**Medium**	**Large**	
Number of Meters	27,253	23,315	3,312	561	65	
$2019 Total	**$4,558,521**	**$2,707,227**	**$438,570**	**$164,834**	**$1,247,889**	
2020 Costs for Service Drops				**$2020 inflation adjustment =**		**1.10146**
Non-network	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**
Number of Meters	450,851	405,846	42,203	2,690	103	9
$2020 Total	**$42,950,696**	**$37,752,951**	**$3,827,930**	**$821,600**	**$407,204**	**$141,011**
Network	**Total**	**Residential**	**Small**	**Medium**	**Large**	
Number of Meters	28,525	24,524	3,365	570	66	
$2020 Total	**$4,847,963**	**$2,920,008**	**$456,917**	**$171,737**	**$1,299,301**	

Total Wires and Related Equipment Costs Including Service Drops

Total Wires and Related Equipment costs for 2019 and 2020 are shown in **Tables 3.30** and **3.31**. Costs for non-network classes are based on the following formula:

$$\frac{(Nonnet\ Capital\ Costs/MW + Nonnet\ O\&M\ Costs/MW) * Inflation * Class\ Coincident\ Peak\ Load * Nonnet\ Capacity}{Total\ Nonnetwork\ Peak\ Load} + Total\ Service\ Drops\ costs\ by\ class$$

Costs for network classes are based on the following formula:

$$\frac{(Netw\ Capital\ Costs/MW + Netw\ O\&M\ Costs/MW) * Inflation * Class\ Coincident\ Peak\ Load * Netw\ Capacity}{Total\ Network\ Peak\ Load} + Total\ Service\ Drops\ costs\ by\ class$$

Table 3.30: 2019 Total Wires and Related Equipment Costs

Non-network		**Network**	
Capital Costs, \$2016/MW	\$41,762	Capital Costs, \$2016/MW	\$135,745
O&M Costs, \$2016/MW	\$4,004	O&M Costs, \$2016/MW	\$2,492
Total Capacity MW	5,603	Total Capacity MW	660

2019 Coincident Peak Load (MW)

	Total	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Non-network	1,152.5	489.9	163.8	255.8	119.0	119.7	4.4
Network	180.5	13.8	20.2	66.7	79.8		
Service Territory	1,333.0						

2019 Wires and Related Equipment Costs — **\$2019 inflation adjustment = 1.07415**

	Total	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Non-network	\$316,521,149	\$153,109,076	\$42,855,478	\$61,932,857	\$28,825,467	\$28,757,876	\$1,040,395
Network	\$102,560,079	\$10,210,201	\$11,398,556	\$36,373,849	\$44,577,472		
Service Territory	\$419,081,227	\$163,319,277	\$54,254,035	\$98,306,706	\$73,402,939	\$28,757,876	\$1,040,395

Table 3.31: 2020 Total Wires and Related Equipment Costs

Non-network				**Network**			
Capital Costs, $2016/MW		$41,762		Capital Costs, $2016/MW		$135,745	
O&M Costs, $2016/MW		$4,004		O&M Costs, $2016/MW		$2,492	
Total Capacity MW		5,603		Total Capacity MW		660	
2020 Coincident Peak Load (MW)							
	Total	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Non-network	1,151.5	490.9	163.4	255.1	118.4	119.6	4.1
Network	180.9	14.0	20.2	66.7	80.0		
Service Territory	1,332.4						
2020 Wires and Related Equipment Costs					**$2020 inflation adjustment =**		**1.10146**
	Total	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Non-network	$325,399,278	$158,160,008	$43,912,814	$63,405,265	$29,446,189	$29,478,682	$996,320
Network	$105,341,081	$10,699,879	$11,670,088	$37,222,043	$45,749,071		
Service Territory	$430,740,360	$168,859,887	$55,582,902	$100,627,308	$75,195,260	$29,478,682	$996,320

3.4.4. Customer Transformers

Customer transformers convert electricity from feeder line voltage (13 or 26 kV) to a lower customer-level voltage and are sized to maximum demand. Larger customers often have one (or more) dedicated transformers that are not shared with other customers. Smaller customers typically share one transformer.

One challenge in a marginal cost study is that there is no single standard type of transformer. Transformers in the City Light system come in many different sizes and might be pole-mounted, underground or network, and each transformer type carries a different unit cost. In this study, Residential and Small General Service classes assume a typical transformer.

For Medium, Large and High Demand, the number of transformers in each size category needed to serve each individual customer was estimated using current engineering design guidelines and each customer's 2017 maximum recorded demand. The frequency of each transformer type appears in column (E) of **Tables 3.37** through **3.39**.

In general, transformers are assigned such that the transformer rating exceeds the customer's maximum demand. An exception to this rule is residential transformers. Ambient temperature affects the loading of transformers; the actual capacity of the transformer can be half again or more as great as its nameplate rating on a very cold day. Since residential customers typically realize their maximum demand when the weather is coldest, residential transformers are undersized. The expected maximum demand on residential transformers typically exceeds the transformer nameplate rating by 50%, or a loading versus rating of 150%. In contrast, transformers for small general service customers are assigned a loading versus rating of 100%.

For network customers, redundant transformer capacity is installed to increase reliability. In a typical network configuration, three lines are brought to three transformers sized such that service can be maintained with any two of the three lines in service.[4]

Transformer Costs and Cost-Related Factors

Table 3.32 summarizes the annual cost per kW of providing transformation services to each of the customer classes. Background information related to developing the costs in **Table 3.32** is presented in **Tables 3.33** and **3.34**. The actual calculations of the transformer costs summarized in **Table 3.32** are developed in **Tables 3.35** through **3.39**.

Table 3.32: Summary of Transformer Costs, $2016

Customer Class	$/kW/Year
Residential	$3.88
Small	$5.06
Medium, Combined	$10.20
Medium, Non-network	$6.18
Medium, Network	$25.28
Large, Combined	$5.48
Large, Non-network	$2.48
Large, Network	$10.23
High Demand	$1.60
Streetlights	$5.06

Transformer Capital Costs

The capital costs of transformers include the current purchase price of the transformer and associated equipment and materials, the labor to set the transformer, an allotment for inventory reserves, and an adjustment for losses through the transformer. The purchase prices used in this analysis are averages of recent actual purchases. The purchase price for each size and type of transformer, network protector and ancillary equipment, including sales tax, is shown in **Table 3.33**. The labor to install the transformer includes the cost of setting the transformer, testing it, installing related equipment when needed (such as network protectors, disconnect switches, etc.) and, in some cases, assembling the transformer. The customer is not billed for any of these tasks except through rates, so this labor is included in marginal transformer costs. However, the labor cost involved in connecting the transformer to the customer's service and the distribution system is recovered through a direct installation charge, so the cost for that labor is not included as part of marginal transformer costs. Material costs including taxes (**Tables 3.35-3.39)** are used to estimate total transformer costs per kW per year for each customer class. The expected life of transformers is 32 years, which results in an annualization rate of .04905.

[4] Smaller network customers were assigned using this "N-1" capacity approach but were assigned fictitious transformer capacities and converted to the minimum network size of 500 kVA.

Table 3.33: Purchase Cost of Transformers, Network Protectors and Ancillary Equipment (including sales tax), $2016

Transformer Type	Transformers	Network Protectors	Ancillary Equipment	Installation Cost	Total Cost
25 kVA, Overhead	$1,882		$403	$1,233	$3,517
25 kVA, Underground	$4,555		$565	$5,986	$11,106
50 kVA, Overhead	$2,549		$467	$1,233	$4,248
50 kVA, Underground	$5,416		$651	$5,986	$12,053
75 kVA, Overhead	$3,706		$539	$1,233	$5,479
75 kVA, Underground	$6,679		$1,044	$5,986	$13,709
100 kVA, Overhead	$5,252		$608	$1,233	$7,093
100 kVA, Underground	$7,798		$1,035	$8,034	$16,866
167 kVA, Overhead	$8,218		$1,154	$1,233	$10,604
167 kVA, Underground	$12,472		$1,697	$8,034	$22,203
750 kVA Commercial Subway	$74,019		$1,577	$12,601	$88,197
1000 kVA Commercial Subway	$56,100		$1,577	$12,602	$70,279
1500 kVA Commercial Subway	$60,433		$249	$6,214	$66,896
2000 kVA Commercial Subway	$82,378		$249	$6,214	$88,841
2500 kVA Commercial Subway	$92,486		$249	$6,214	$98,949
5000 kVA Commercial Subway	$147,584		$17,236	$53,111	$217,930
7500 kVA Commercial Subway	$192,522		$16,968	$42,779	$252,269
15000 kVA Commercial Subway	$456,465		$16,901	$42,779	$516,144
500 kVA Network	$46,049	$27,294	$12,894	$32,102	$118,339
750 kVA Network	$49,012	$26,816	$12,964	$32,102	$120,894
1000 kVA Network	$55,831	$25,669	$13,003	$32,102	$126,605
1500 kVA Network	$75,683	$35,860	$13,994	$34,287	$159,824
2000 kVA Network	$85,042	$58,238	$14,068	$34,287	$191,634

Transformer O&M Costs

Reported O&M costs vary year to year, so a three-year average from 2014 to 2016, adjusted for inflation, is used to calculate total O&M costs. O&M costs are reported in FERC account 595 as a system total, not by specific customer classes. To determine the class-specific O&M, we express class-specific O&M as a function of capital by using an O&M factor--which is total O&M as a percentage of total capital costs. Class-specific O&M is then determined by multiplying the capital costs for a given class by the O&M factor. However, not all transformers incur O&M expenses; transformers of 167 kVA and smaller receive no maintenance and are simply replaced on failure. Therefore, in this analysis, annual O&M costs are applied only to the transformers equal to or larger than 500 kVA and the total capital costs used to calculate the O&M factor are adjusted accordingly. For this analysis, the O&M factor is estimated as 18.57% of the annual capital cost.

Class Load Factors Used in Transformer Cost Calculation

Similar to how we calculate and allocate other distribution costs, we first determine the cost per MW of transformers for each customer class. In the case of transformers, however, we allocate these costs to each class and arrive at the total cost for the service area by using the non-coincident maximum demand, or connected load, of each customer class instead of coincident peak demand. This is because transformers are installed to meet customer-specific peak loads, regardless of the system peak.

Table 3.34 details load factor assumptions.

Table 3.34: 2017 Load Factors by Customer Class

Customer Class	Adjusted Annual MWH	Connected Load, MW		Load Factor	
Residential	3,136,821	941.3	(1)	0.3804	(4)
Residential Non-network	3,051,356	915.4	(2)	0.3805	
Residential Network	85,466	25.9	(3)	0.3772	
Small	1,222,301	367.1	(1)	0.3801	(4)
Small Non-network	1,089,456	326.9	(2)	0.3805	
Small Network	132,845	40.2	(3)	0.3772	
Medium	2,368,275	716.7		0.3772	(4)
Medium Non-network	1,879,234	568.7		0.3772	(4)
Medium Network	489,041	148.0		0.3772	(4)
Large	1,478,965	460.2		0.3669	(4)
Large Non-network	880,760	281.1		0.3577	(4)
Large Network	598,205	179.0		0.3814	(4)
High Demand	1,042,562	333.3		0.3571	(4)
Streetlights	59,183	13.5		0.5000	(5)

Notes:

(1) Sum of Non-network and Network.

(2) Because customers in these classes do not have demand meters, connected load must be estimated by taking adjusted annual MWh divided by the number of hours in the year (8760 or 8784 for a leap year) divided by load factor.

(3) Residential and Small Network customers are assumed to have same load factor as Medium Network customers.

(4)The load factors are calculated by first dividing the adjusted annual MWh by 8760 (8784 for a leap year) to get average MW and then dividing that by the class non-coincident maximum demand (i.e., connected load) from 2017 billing data, shown in the table.

(5) Streetlights are on for 12 hours per day, therefore, their load factor is assumed to be 0.5.

Special Transformer Information by Class

Consistent with previous Cost of Service analyses, the Residential and Small General Service non-network load factors are assumed to be 0.3805. The transformer loadings for residential customers are estimated using the following formula:

$$Maximum\ Demand = 12kW + 0.0003(Annual\ kWh)$$

where *Annual kWh* is the total energy for all the customers on that transformer. For each 1,000 kWh of added annual load on a transformer, the maximum demand increases by 0.3 kW.

Since $Load\ Factor = Average\ kW/Peak\ \ kW$, then $Marginal\ Load\ Factor = Change\ in\ Average\ kW/Change\ in\ Peak\ kW = \frac{1{,}000\ kWh}{8{,}760\ h * 0.3\ kW} = 0.3805$

In the absence of adequate load research, the transformer group load factor for the Small General Service class has been assumed to be 0.3805 as well.

All customers in the Medium, Large, and High Demand General Service classes have demand meters, so load factors can be computed directly from billing data.[5] The load factor is calculated for each class by dividing 2017 average class energy consumption in MWh by 8,760 hours and then dividing the result by the total class non-coincident maximum demand for 2017.[6]

Streetlights do not have meters and are served at distribution voltage (assumed to be 26 kV) by short service drops from nearby transformers. For costing purposes, streetlights are treated the same as Small General Service customers; they have transformer capacity assigned according to the same design rules, and the same unit cost of transformer capacity.

Streetlights are on for 12 hours per day, therefore their load factor is assumed to be 0.5.

[5] Unlike Residential and Small General Service customers, where customers are grouped to one transformer, the rule for Medium, Large, and High Demand customers is at least one transformer to one customer. As a consequence, it is the load factor of each individual customer (or on each individual meter) that is relevant.

[6] In a non-leap year 8,760 hours should be used; in a leap year 8,784 hours should be used.

Transformer Costs by Customer Class

In **Tables 3.35** through **3.39**, all of the factors discussed in the preceding sections are combined to yield total annual transformer costs per kW for each customer class. Annual transformer costs per kW for Residential and Small General Service (**Tables 3.35** and **3.36)** are derived as follows:

1. Compute weighted average costs of transformers, ancillary equipment and materials, and installation for a 50 kVA transformer using the percentages of the overhead and underground transformers in the system.
2. Adjust transformer costs for losses.
3. Compute the Annualized Capital Cost (ACC) by summing the transformer costs (adjusted for losses), and ancillary equipment and materials costs, then multiplying this sum by the inventory reserve factor, adding installation costs to this amount, and finally, multiplying this total by the annualization factor.
4. Compute the Levelized Capital Cost (LCC) by dividing ACC by the transformer size multiplied by the loading rate (i.e., the percentage of loading vs rating).

Table 3.35: Residential Class Transformer Cost, $2016

	Total Residential Transformer Cost =			**$3.88 /kW/year**		
	Transformer Size (kVA)	**Transformer Cost**	**Ancillary Equipment and Material Cost**	**Installation Cost**	**Frequency (#)**	**Total Capacity (kVA)**
	(A)	(B)	(C)	(D)	(E)	(F)
(1)	50	$3,122	$504	$2,183	n.a.	n.a.
Assumptions:						
(a)	Inventory Reserve Factor			1.0175		
(b)	Economic Life			32		
(c)	Annualization Factor			0.0490466		
(d)	Loading vs. Rating			150%		
(e)	Losses			1.77%		
(f)	O&M as % of Annual Capital Cost			0%		
(g)	50 kVA OH Transformer			$2,549		
(h)	50 kVA UG Transformer			$5,416		
(i)	50 kVA OH Ancillary Equipment Cost			$467		
(j)	50 kVA UG Ancillary Equipment Cost			$651		
(k)	50 kVA OH Labor & Installation Cost			$1,233		
(l)	50 kVA UG Labor & Installation Cost			$5,986		
(m)	% Overhead transformers			80%		

Annual Capital Cost Calculations:			
Transformer Cost (TC) = (B) =	(g) * (m) + (h) * [1-(m)]	$3,122	
Ancillary Equipment and Material Cost (C) =	(i) * (m) + (j) * [1-(m)]	$504	
Installation Cost (D) =	(k) * (m) + (l) * [1-(m)]	$2,183	
Adjusted for Losses (TCAFL) =	TC * {1 / [1 - (e)]}	$3,178	
Annualized Capital Cost (ACC) =	{(a)*[(TCAFL)+ (C)] + (D)} *(c)	$291	/year
Levelized Capital Cost (LCC) =	ACC / [(A) * (d)]	$3.88	/kW/year

Table 3.36: Small General Service Class and Streetlight Transformer Cost, $2016

	Small General Service Class and Streetlight Transformer Cost =				$5.06 /kW/year	
	Transformer Size (kVA)	**Transformer Cost**	**Ancillary Equipment and Material Cost**	**Installation Cost**	**Frequency (#)**	**Total Capacity (kVA)**
	(A)	(B)	(C)	(D)	(E)	(F)
(1)	50	$2,835	$485	$1,708	n.a.	n.a.
Assumptions:						
(a)	Inventory Reserve Factor			1.0175		
(b)	Economic Life			32		
(c)	Annualization Factor			0.0490466		
(d)	Loading vs. Rating			100%		
(e)	Losses			2.31%		
(f)	O&M as % of Annual Capital Cost			0%		
(g)	50 kVA OH Transformer Cost			$2,549		
(h)	50 kVA UG Transformer Cost			$5,416		
(i)	50 kVA OH Ancillary Equipment Cost			$467		
(j)	50 kVA UG Ancillary Equipment Cost			$651		
(k)	50 kVA OH Labor & Installation Cost			$1,233		
(l)	50 kVA UG Labor & Installation Cost			$5,986		
(m)	% Overhead transformers			90%		

Annual Capital Cost Calculations:			
Transformer Cost (TC) = (B) =	(g) * (m) + (h) * [1-(m)]	$2,835	
Ancillary Equipment and Material Cost (C) =	(i) * (m) + (j) * [1-(m)]	$485	
Installation Cost (D) =	(k) * (m) + (l) * [1-(m)]	$1,708	
Adjusted for Losses (TCAFL) =	TC * {1 / [1 - (e)]}	$2,902	
Annualized Capital Cost (ACC) =	{(a) *[(TCAFL)+ (C)] + (D)} * (c)	$253	
Levelized Capital Cost (LCC) =	ACC / [(A) * (d)]	$5.06	/kW/year

For Medium, Large, and High Demand General Service classes, transformers are assigned based on customer demand and service environment data from 2015. Estimates of the number of transformers in each size category are shown in the "Frequency" column. The annual cost per kW for each of these classes, seen in **Tables 3.37**, **3.38**, and **3.39**, is derived as follows:

1. For transformers of 25-167 kVA, the weighted average costs of transformers, ancillary equipment and materials, and installation are computed using the percentages of the overhead and underground transformers in the system. For larger size transformers, costs are taken directly from **Table 3.33**.
2. The Annualized Transformer Cost (ATC) is calculated for each transformer size by multiplying the number of transformers by their respective transformer cost. These are summed together and the sum is multiplied by the inventory reserve factor and annualization factor to get the total ATC.
3. The ATC adjusted for losses (denoted as AFL in tables) is computed by multiplying it by a losses percentage, which varies for non-network and network.
4. Similarly, to get non-network and network Annualized Materials and Installation Cost (AMIC) we first multiply the number of transformers of a particular size by their respective material costs to get the total material costs for each transformer size, then we add these total costs together and multiply this sum by the inventory reserve factor. Next, we multiply the number of transformers of a particular size by their respective installation costs and add them together. Lastly, we sum total material costs adjusted with a reserve factor and total installation costs and multiply this sum by the annualization factor. To get AMIC for the total system we add AMIC for non-network and network together.
5. Annualized Capital Cost (ACC) is the sum of AFL and AMIC.
6. Levelized Capital Cost (LCC) is derived by dividing ACC by the class non-coincident maximum demand.
7. Annual O&M cost (AOM) is calculated by multiplying LCC by the O&M factor and, in the case of the Medium General Service class, by the percent of total capital cost that is subject to O&M. (100% of transformer capital costs are subject to O&M in the Large and High Demand classes.)
8. Finally, AOM and LCC are added together to obtain the total annual transformer cost per kW for each class.

Table 3.37: Medium General Service Class Transformer Cost, $2016

Medium General Service Transformer Cost, Combined =				$10.20	/kW/year
Medium General Service Transformer Cost, Non-network =				$6.18	/kW/year
Medium General Service Transformer Cost, Network =				$25.28	/kW/year
Transformer Size (kVA)	**Transformer Cost**	**Ancillary Equipment and Material Cost**	**Installation Cost**	**Frequency (#)**	**Total Capacity (kVA)**
(A)	(B)	(C)	(D)	(E)	(F)
Small (pole/sub)					
(1) 25	$2,416	$435	$2,183	1,842	46,050
(2) 50	$3,122	$504	$2,183	2,745	137,250
(3) 75	$4,301	$640	$2,183	1,215	91,125
(4) 100	$5,762	$693	$2,593	660	66,000
(5) 167	$9,069	$1,262	$2,593	789	131,763
% Overhead transformers	80%			**Total**	**472,188**
Commercial Subway					
(6) 750	$74,019	$1,577	$12,601	126	94,500
(7) 1,000	$56,100	$1,577	$12,602	59	59,000
(8) 1,500	$60,433	$249	$6,214	31	46,500
				Total	**200,000**
Network					
(9) 500	$46,049	$40,188	$32,102	505	252,500
(10) 750	$49,012	$39,780	$32,102	45	33,750
				Total	**286,250**

Assumptions:	**Common**	**Non-network**	**Network**
(a) Inventory Reserve Factor	1.0175		
(b) Economic Life, years	32		
(c) Annualization Factor	0.0490466		
(d) Losses		0.98%	0.44%
(e) Class Noncoincident Max Demand, kW	723,316	571,158	152,159
(f) O&M as % of Annual Capital Cost	18.57%		
(g) % of Capital Cost Subject to O&M	62.26%	25.83%	100.00%

Annual Capital and O&M Cost Calculations:	**Combined**	**Non-network**	**Network**
Annualized Transformer Cost (ATC) = {[(a)*SUM(1...10)(B*E)]}*(c)	$3,452,150	$2,181,563	$1,270,587
Adj. for Losses (AFL) = ATC / (1-d) [$/kW/yr]	$3,479,299	$2,203,154	$1,276,145
Ann. Mat'l & Install (AMIC)={(a)*SUM(1...10)(C*E)+SUM(1...10)(D*E)}*(c)	$3,132,866	$1,164,732	$1,968,134
Ann. Cap. Cost (ACC) = AFL+AMIC [$/ year]	$6,612,166	$3,367,886	$3,244,279
Levelized Cap.Cost (LCC) = ACC/(e) [$/kW/yr]	$9.14	$5.90	$21.32
Ann.O&M (AOM) = LCC * (f) *(g) [$/kW/yr]	$1.06	$0.28	$3.96
Total Cost = LCC + AOM [$/kW/yr]	**$10.20**	**$6.18**	**$25.28**

Table 3.38: Large General Service Class Transformer Cost, $2016

Large General Service Transformer Cost, Combined =					**$5.48**	**/kW/year**
Large General Service Transformer Cost, Non-network =					**$2.48**	**/kW/year**
Large General Service Transformer Cost, Network =					**$10.23**	**/kW/year**
	Transformer Size (kVA)	**Transformer Cost**	**Ancillary Equipment and Material Cost**	**Installation Cost**	**Frequency (#)**	**Total Capacity (kVA)**
	(A)	(B)	(C)	(D)	(E)	(F)
Commercial Subway						
(1)	750	$74,019	$1,577	$12,601	5	3,750
(2)	1,000	$56,100	$1,577	$12,602	5	5,000
(3)	1,500	$60,433	$249	$6,214	38	57,000
(4)	2,000	$82,378	$249	$6,214	48	96,000
(5)	2,500	$92,486	$249	$6,214	11	27,500
(6)	5,000	$147,584	$17,236	$53,111	7	35,000
(7)	7,500	$192,522	$16,968	$42,779	7	52,500
					Total	**276,750**
Network						
(8)	500	$46,049	$40,188	$32,102	0	0
(9)	750	$49,012	$39,780	$32,102	45	33,750
(10)	1,000	$55,831	$38,672	$32,102	12	12,000
(11)	1,500	$75,683	$49,854	$34,287	117	175,500
(12)	2,000	$85,042	$72,305	$34,287	30	60,000
					Total	**281,250**
Assumptions:				**Common**	**Non-network**	**Network**
(a)	Inventory Reserve Factor			1.0175		
(b)	Economic Life, years			32		
(c)	Annualization Factor			0.0490466		
(d)	Losses				0.89%	0.40%
(e)	Class Non-coincident Max Demand, kW			468,592	287,316	181,276
(f)	O&M as % of Annual Capital Cost			18.57%		
Annual Capital and O&M Cost Calculations:				**Combined**	**Non-network**	**Network**
Annualized Transformer Cost (ATC) = {[(a)*SUM(1...12)(B*E)]}*(c)				$1,226,711	$513,986	$712,725
Adj. for Losses (AFL) = ATC / (1-d) [$/kW/yr]				$1,234,157	$518,601	$715,556
Ann. Mat'l & Install (AMIC)={(a)*SUM(1...12)(C*E)+SUM(1...12)(D*E)}*(c)				$931,393	$82,606	$848,787
Ann. Cap. Cost (ACC) = AFL+AMIC [$/ year]				$2,165,550	$601,208	$1,564,342
Levelized Cap.Cost (LCC) = ACC/(e) [$/kW/yr]				$4.62	$2.09	$8.63
Ann.O&M (AOM) = LCC * (f) [$/kW/yr]				$0.86	$0.39	$1.60
Total Cost = LCC + AOM [$/kW/yr]				**$5.48**	**$2.48**	**$10.23**

Table 3.39: High Demand General Service Class Transformer Cost, $2016

Total High Demand General Service Class Transformer Cost =	$1.60/kW/year					
	Transformer Size (kVA)	Transformer Cost	Ancillary Equipment and Material Cost	Installation Cost	Frequency (#)	Total Capacity (kVA)
	(A)	(B)	(C)	(D)	(E)	(F)
Commercial Subway						
(1)	5,000	$147,584	$17,236	$53,111	2	5,000
(2)	7,500	$192,522	$16,968	$42,779	0	7,500
(3)	15,000	$456,465	$16,901	$42,779	17	240,000
Assumptions:						
(a)	Inventory Reserve Factor			1.0175		
(b)	Economic Life, years			32		
(c)	Annualization Factor			0.0490466		
(d)	Losses			0.89%		
(e)	Class Non-coincident Max Demand, kW			342,302		
(f)	O&M as % of Annual Capital Cost			18.57%		
Annual Capital and O&M Cost Calculations:						
Annualized Transformer Cost (ATC) = {[(a) * SUM(1...3)(B * E)]} * (c)					$401,988	
Adj. for Losses (AFL) = ATC / (1-d) [$/kW/yr]					$405,598	
Ann. Mat'& Install (AMIC) = (a)*SUM(1...3)(C*E)+SUM(1...3)(D*E)}*(c)					$56,937	
Ann. Cap. Cost (ACC) = AFL+AMIC [$/ year]					$462,534	
Levelized Cap.Cost (LCC) = ACC/(e) [$/kW/yr]					$1.35	
Ann.O&M (AOM) = LCC * (f) [$/kW/yr]					$0.25	
Total Cost = LCC +AOM [$/kW/yr]					**$1.60**	

Total Transformer Costs

Table 3.40 presents total transformer costs for 2019 and 2020. Costs for non-network classes are based on the following formula:

$$Peak\ MW * Nonnetwork\ Transformer\ Cost/kW * Inflation * 1{,}000$$

where $Peak\ MW = Load\ MWh/Load\ Factor\ /8{,}760\ (or\ 8{,}784\ for\ a\ leap\ year)$.

Similarly costs for network classes are based on the following formula:

$$Peak\ MW * Network\ Transformer\ Cost/kW * Inflation * 1{,}000$$

where $Peak\ MW$ is defined as above.

Load data does not include losses and comes from **Tables 3.1** and **3.2**. The load factor data comes from **Table 3.34**.

Table 3.40: 2019 and 2020 Total Transformer Costs

		Residential	Small	Medium	Large	High Demand	Lights
Non-network Transformer Costs $2016/kW		$3.88	$5.06	$6.18	$2.48	$1.60	$5.06
Network Transformer Costs* $2016/kW		$17.76	$17.76	$25.28	$10.23		
2019 Transformer Costs				$2019 inflation adjustment =	1.07415		
Total Non-network	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Load, MWh	7,977,229	3,060,754	1,083,348	1,847,115	888,540	1,050,943	46,529
Load Factor		0.3805	0.3805	0.3772	0.3577	0.3571	0.5000
Peak Load, MW	2,432	918	325	559	284	336	11
$2019 Total Costs	$10,692,566	$3,825,047	$1,765,434	$3,710,364	$755,790	$578,228	$57,702
Downtown Network	**Total**	**Residential**	**Small**	**Medium**	**Large**		
Load, MWh	1,301,363	86,673	133,643	482,096	598,951		
Load Factor		0.3772	0.3772	0.3772	0.3814		
Peak Load, MW	392	26	40	146	179		
$2019 Total Costs	$7,203,750	$500,283	$771,399	$3,961,878	$1,970,190		
Total Service Territory	$17,896,315	$4,325,330	$2,536,833	$7,672,243	$2,725,980	$578,228	$57,702
2020 Transformer Costs				$2020 inflation adjustment =	1.10146		
Total Non-network	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Load, MWh	7,936,953	3,076,933	1,072,069	1,826,575	877,334	1,040,484	43,558
Load Factor		0.3805	0.3805	0.3772	0.3577	0.3571	0.5000
Peak Load, MW	2,420	923	322	553	280	333	10
$2020 Total Costs	$10,904,534	$3,943,027	$1,791,471	$3,762,388	$765,230	$587,028	$55,390
Downtown Network	**Total**	**Residential**	**Small**	**Medium**	**Large**		
Load, MWh	1,293,187	88,119	132,527	478,009	594,531		
Load Factor		0.3772	0.3772	0.3772	0.3814		
Peak Load, MW	389	27	40	145	178		
$2020 Total Costs	$7,339,502	$521,564	$784,406	$4,028,163	$2,005,370		
Total Service Territory	**$18,244,037**	**$4,464,590**	**$2,575,877**	**$7,790,551**	**$2,770,601**	**$587,028**	**$55,390**

* Residential and Small network transformer costs are assumed to be an average of Medium and Large network transformer costs.

3.5 Customer Costs

Customer costs are comprised of two parts: customer service costs and meter costs. Customer service costs are expenditures associated with collecting meter readings, processing customer bills, answering customer phone calls, opening and closing accounts, writing-off uncollectable bills and performing other customer service related work. Meter costs are the costs of the meters, meter installation and O&M. The total marginal costs of customer service and the total marginal cost of meters are derived in Sections 3.5.1 and 3.5.2, respectively, and then combined to get total customer costs in Section 3.53.

3.5.1 Customer Service Costs

The marginal customer service cost per meter is a sum of per meter costs associated with each FERC program code listed in **Table 3.41.** For each customer class, total customer service costs were calculated by deriving 2016 marginal customer service costs per meter, converting them into $2019 and $2020 and then multiplying them by the number of meters projected in 2019 and 2020.

Table 3.41: 2016 Customer Service Costs by FERC Code

FERC Code[7]	FERC #	2016
Revenue		
MISC SVC REV-MISC COML EQ RENT	45110	159,612
MISC SVC REV-ACCT CHANGE FEE(R	45130	1,825,904
MISC SVC REV-ACCT CHANGE FEE(C	45131	32,866
MISC SVC REV-RECONCT & FIELD C	45150	387,977
Total		**2,406,360**
Expenses		
METER READING SUPERVISION	90101	371,675
METER READING EXPENSES	90201	4,114,057
DISCON SERV NON-PAYMENT	90301	624,987
CR INVESTIGATIONS & RECORDS	90311	2,832,644
COLLECTING-LIGHT DEPT	90321	4,541,920
COL-CITY TREAS BNKS,AM EXPR	90341	2,356,712
CUST CONTR & ORDERS	90351	10,516,469
BILL REV ACCTG & MAILING	90361	3,858,973
UNCOLLECTIBLE ACCT-ELEC UTILTY	90401	5,189,360
UNCOLLECTIBLE ACCT-SUNDRY SALE	90403	1,760,382
MISC CUST ACCT EXP	90501	996,439
SUPERVISION-RESIDENTIAL	90701	553,123
SUPV-CMML & IND	90711	0
CUST ASST EXP- RESDL	90801	3,109,336
CUST ASST EXP-CMML& IND	90811	717,747
MISC CUST SERV & INFO EXP	91001	1,075,399
GENERAL ADVERTISING EXPENSES	93010	16,796
Total		**42,636,019**

[7] FERC Names are listed as they appear in the system; some line items may look abbreviated or truncated.

Customer Service Allocation Factors

Each of the customer service costs listed in **Table 3.41** was allocated among customer classes and then divided by the number of meters to get per meter costs. **Table 3.42** summarizes the customer data used to derive the customer service allocation factors in **Table 3.44**.

Table 3.42: 2016 Customer Information Data

	Total	Residential	Small	Medium	Large	High Demand
Meter Count	435,678	387,926	44,400	3,184	159	10
Non-network		367,813	41,210	2,656	98	10
Network		20,113	3,189	528	61	
Customer Count	431,828	385,708	42,778	3,158	174	10
Bills Issued Count (Annual Average)	2,914,198	2,576,556	299,155	36,528	1,847	112
Annual MWh Consumption	9,067,050	3,000,878	1,195,373	2,379,228	1,481,981	1,009,590
Payment						
Cash or Check	$464,083,783	$116,782,277	$67,567,735	$137,514,708	$97,515,368	$44,703,696
Credit Card	$90,296,856	$51,279,491	$9,759,819	$13,812,970	$7,323,235	$8,121,341
Web/Metavante	$177,402,174	$100,088,262	$19,775,255	$28,696,090	$13,049,864	$15,792,703
Interfund transfer	$12,490,722	$456,293	$2,158,985	$6,534,950	$3,340,494	$0
Uncollectibles	$4,390,215	$3,504,439	$565,624	$198,235	$0	$0

Assumptions used in the analysis of customer information data include:

i. Customer count data was consolidated by customer class and not by location (network versus non-network) since none of the FERC accounts allocated on the basis of customer count required differentiation by location.
ii. The bills issued information is the total for each customer class. Residential customers are generally billed every two months, while all other customer classes are billed monthly.
iii. The number of accounts can be less than the number of meters since some customers, particularly multifamily dwellings and larger businesses, have multiple meters billed to one account.

Meter reading expenses are allocated using weighted meter counts, summarized in **Table 3.43**. Weighting factors were developed for the Residential, Small General Service, and Medium General Service customer classes based on an estimate of the amount of meter reading resources used for each class. At the time of this cost of service study, most manually-read meters for Residential, Small General Service, and Medium General Service customers had already been replaced with advanced meters that could be read electronically, but the replacement process had not yet been completed for all of these customers. Therefore, this cost of service study assumed no change from past meter reading practices for these customer classes and used the same weighting factors as all prior rate cases going back to the 2007-2008 rate case. These weighting factors considered whether the route was walk or drive and the number of meter reads per year. Large and High Demand General Service meters are read electronically and the billing information is prepared by separate staff. The costs of the meter reading activities of these two customer classes are isolated and treated separately. Therefore, the weights for these two classes are assigned the value of 1.0.

Table 3.43: Weighted Meter Reading Counts

	Total	**Residential**	**Small**	**Medium**	**Large**	**High Demand**
Meter Count	435,678	387,926	44,400	3,184	159	10
Non-network		367,813	41,210	2,656	98	
Network		20,113	3,189	528	61	
Meter Reading						
Non-network		1.00	1.18	2.98	1	1
Network		1.78	1.7	2.13	1	
Weighted Meter	466,872	403,614	54,050	9,039	159	10
Non-network		367,813	48,628	7,915	98	
Network		35,802	5,422	1,124	61	

Table 3.44 summarizes the allocation factors used for different customer costs. Some factors allocate costs only over Residential, Small and Medium General Service classes (factor names with suffixes _R_S_M). Other factors allocate costs only over Large and High Demand General Service classes (factor names with suffixes _L_H). Yet others allocate costs over all classes (factor names with the suffix _ALL).

Table 3.44: Customer Cost Allocation Factors

	Total	Residential	Small	Medium	Large	High Demand
METER READING						
MR_R_S_M	100%					
Non-network		78.81%	10.42%	1.70%		
Network		7.67%	1.16%	0.24%		
MR_L_H	100%					
Non-network					58.08%	6.11%
Network					35.81%	
MR_ALL	100%					
Non-network		78.78%	10.42%	1.70%	0.02%	0.00%
Network		7.67%	1.16%	0.24%	0.01%	
METER COUNT						
MC_R_S_M	100%	89.07%	10.19%	0.73%		
MC_L_H	100%				93.89%	6.11%
MC_ALL	100%	89.04%	10.19%	0.73%	0.04%	0.00%
Wgt. Avg. MC_ALL and MC_L_H	100%	59.38%	6.80%	0.49%	31.30%	2.04%
(2/3 to R, S,& M, and 1/3 to L & HD)						
CUSTOMER COUNT						
C_R_S_M	100%	89.36%	9.91%	0.73%		
C_S_M	100%		93.12%	6.88%		
C_L_H	100%				94.35%	5.65%
C_S_M_L_H	100%		92.75%	6.85%	0.38%	0.02%
C_ALL	100%	89.32%	9.91%	0.73%	0.04%	0.00%
BILLS ISSUED						
BI_R_S_M	100%	88.5%	10.3%	1.3%		
BI_ALL	100%	88.4%	10.3%	1.3%	0.1%	0.0%
BI_L_H	100%				94.3%	5.7%
kWh RELATED						
kWh	100%	33.10%	13.18%	26.24%	16.34%	11.13%
PAYMENT METHOD						
Cash or Check	100%	25.16%	14.56%	29.63%	21.01%	9.63%
Credit Card	100%	56.79%	10.81%	15.30%	8.11%	8.99%
Metavante	100%	56.42%	11.15%	16.18%	7.36%	8.90%
Average of Credit Card and Metavante	100%	56.54%	11.03%	15.88%	7.61%	8.93%
OTHER						
EU_BAD_DEBT	100%	79.82%	12.88%	4.52%	2.78%	
EUC_BAD_DEBT	100%		63.86%	22.38%	13.76%	

Customer Service Costs per Meter Computations

The results of 2016 customer service expenditure and revenue allocations among customer classes by FERC program codes are presented in **Tables 3.45-3.60**. The last line in each table shows marginal costs per meter associated with each FERC program code for each customer class.

Meter Reading Supervision and Expenses

Over 98 percent of the expenditures for program code 90201 originated from Organization (Org) Units 472-Meter Reading and 473-Technical Metering[8]. An allocation subtotal was computed for these organization units. The remaining 2 percent of expenditures was allocated in proportion to this subtotal. **Table 3.45** summarizes these results.

Table 3.45: Meter Reading Supervision and Expenses (FERC 90101 and 90201)

	Allocation Factor	Total	Residential	Small	Medium	Large	High Demand
FERC 90101		$371,675					
Non-network	MR_ALL		$292,814	$38,712	$6,301	$78	$8
Network	MR_ALL		$28,502	$4,317	$895	$48	
FERC 90201							
Labor							
472 Meter Reading		$3,811,168					
Non-network	MR_R_S_M		$3,003,613	$397,102	$64,637		
Network	MR_R_S_M		$292,361	$44,278	$9,176		
473 Technical		$123,106					
Non-network	MR_L_H					$71,498	$7,522
Network	MR_L_H					$44,086	
Non-Labor							
472 Meter Reading		$128,805					
Non-network	MR_ALL		$101,476	$13,416	$2,184	$27	$3
Network	MR_ALL		$9,877	$1,496	$310	$17	
Total Allocated		$4,063,079					
Non-network			$3,105,089	$410,518	$66,821	$71,525	$7,525
Network			$302,239	$45,774	$9,486	$44,103	
Overall Allocation							
Non-network			76.42%	10.10%	1.64%	1.76%	0.19%
Network			7.44%	1.13%	0.23%	1.09%	
Total FERC 90201		$4,114,057					
Non-network			$3,144,047.3	$415,668.6	$67,659.1	$72,422.4	$7,619.6
Network			$306,030.6	$46,348.1	$9,605.2	$44,656.2	
Total FERC 90101 and 90201		$4,485,732					
Non-network			$3,436,862	$454,381	$73,960	$72,501	$7,628
Network			$334,532	$50,665	$10,500	$44,704	
Meters							
Non-network			367,813	41,210	2,656	98	10
Network			20,113	3,189	528	61	
$2016/Meter							
Non-network			$9.34	$11.03	$27.85	$738.57	$738.57
Network			$16.63	$15.88	$19.90	$738.57	

[8] Many expenditures in the customer service cost analysis are broken out into labor and non-labor for allocation purposes. As in past years, overhead costs are combined with labor expenses for allocation purposes.

Disconnect Service Non-Payment and Uncollectible Accounts

FERC account 90301, disconnect service non-payment expenses, is directly related to uncollectibles. Costs associated with uncollectible accounts in FERC accounts 90401 and 90403 are also associated with uncollectible accounts. These three accounts are all allocated by EU_BAD_DEBT shares as seen in **Table 3.46**.

Table 3.46: Disconnect Service Non-Payment (FERC 90301) and Uncollectible Accounts (FERC 90401 and 90403)

	Allocation Factor	Total	Residential	Small	Medium	Large	High Demand
FERC 90301	EU_BAD_DEBT	$624,987	$498,888	$80,522	$28,221	$17,356	$0
FERC 90401	EU_BAD_DEBT	$5,189,360	$4,142,347	$668,584	$234,320	$144,110	$0
FERC 90403	EU_BAD_DEBT	$1,760,382	$1,405,205	$226,803	$79,488	$48,886	$0
Total		$7,574,728	$6,046,440	$975,908	$342,028	$210,352	$0
Meters			387,926	44,400	3,184	159	10
$2016/Meter			$15.59	$21.98	$107.43	$1,325.53	$0.00

Credit Investigations and Records

Org Units 463 and 464 contributed over 99.5% of the charges to FERC Program Code 90311. Labor related expenditures were associated with serving Residential, Small and Medium General service customers and were allocated accordingly. In the past, non-labor expenditures were allocated directly to the residential class because for both org units the Residential class accounted for the majority of the nonlabor costs. Org Unit 464 is still allocated all to the residential class but 463 is allocated to Residential, Small and Medium because the majority of the costs are no longer accounted for by only the Residential class.[9] **Table 3.47** has detailed results.

[9] Org Unit 464 had non-labor charges of $2.1 million of which 91% was for interfund payments for the Department of Neighborhoods Pay Center Bill Acceptance program and for the Human Services Department (HDS) for the Mayor's Office for Senior Citizens (MOSC). These were directly related to residential count and so the entire Org. Unit was allocated to the residential class. In the past, Org Unit 463 was chiefly comprised of costs for Project Share which are residential utility discount program related. In 2016 this program did not contribute to Org. Unit 463 and thus the non-labor portion is allocated across Residential, Small and Medium General Service customers.

Table 3.47: Credit Investigations and Records (FERC 90311)

	Allocation Factor	Total	Residential	Small	Medium	Large	High Demand
FERC 90311							
Labor							
463 Credit	C_R_S_M	$448,672	$400,923	$44,466	$3,283		
464 Customer	C_R_S_M	$297,970	$266,259	$29,531	$2,180		
Non-Labor							
463 Credit	C_R_S_M	$46,268	$41,344	$4,585	$339		
464 Customer	DIRECT:RES	$2,101,851	$2,101,851				
Total Allocated		$2,894,761	$2,810,377	$78,582	$5,801		
Overall Allocation Ratios			97.08%	2.71%	0.20%		
Total FERC 90311		$2,832,644	$2,750,071	$72,896	$5,677		
Meters			387,926	44,400	3,184	159	10
$2016/Meter			$7.09	$1.73	$1.78		

Collecting-Light Department

The total dollars allocated in **Table 3.48** represent over 99% of all charges to FERC program code 90321. The customer class totals from these allocated expenditures were computed and an overall allocation factor was developed. This overall factor was applied to the program code 90321 total of $4,541,920 to compute the final class allocations.

Table 3.48: Collecting-Light Department (FERC 90321)

	Allocation Factor	Total	Residential	Small	Medium	Large	High Demand
FERC 90321							
Labor							
341 North Customer	C_R_S_M	$124,47	$111,227	$12,336	$911	$0	$0
352 South Customer	C_R_S_M	$68,657	$61,350	$6,804	$502	$0	$0
431 Account Executives	C_L_H	$92	$0	$0	$0	$87	$5
463 Credit	C_R_S_M	$722,17	$645,321	$71,572	$5,284	$0	$0
464 Customer Accounts[10]	C_R_S_M	$173,72	$155,237	$17,217	$1,271	$0	$0
522 IT Operations	C_ALL	$11,233	$10,033	$1,113	$82	$5	$0
523 IT Applic Dev Serv[4]	C_ALL	$501,17	$447,645	$49,648	$3,665	$201	$12
000 Financial Statement	C_ALL	-	-$106,620	-$11,825	-$873	-$48	-$3
Non-Labor							
463 Credit	C_R_S_M	$43,673	$39,025	$4,328	$320	$0	$0
522 IT Operations	C_ALL	$3,012,5	$2,690,771	$298,431	$22,032	$1,21	$72
Total Allocated		$4,538,3	$4,053,990	$449,624	$33,194	$1,45	$87
Overall Allocation Ratios			89.33%	9.91%	0.73%	0.03%	0.00%
Total FERC 90321		$4,541,9	$4,057,178	$449,977	$33,220	$1,45	$87
Meters			387,926	44,400	3,184	159	10
$2016/Meter			$10.46	$10.13	$10.43	$9.18	$8.44

Collections-City Treasury Banks, American Express

These fees were allocated to the customer classes in proportion to the average amount of payments made by the customer classes using credit. **Table 3.49** reports the results.

Table 3.49: Collection-City Treasury, Banks, Am Expr (FERC 90341)

	Allocation Factor	Total	Residential	Small	Medium	Large	High Demand
FERC 90341	Average of Credit Card and Metavante	$2,356,712	$1,332,580	$260,015	$374,232	$179,356	$210,529
Meters			387,926	44,400	3,184	159	10
$2016/Meter			$3.44	$5.86	$117.55	$1,130.21	$20,384.60

[10] For this FERC account, there is a difference between the L22 and Cognos for the reported dollar value for org unit 464 and 523. As the L22 is the official record, these numbers are used for these Org Units. The L22 is not broken out between Labor and Non-Labor and so the entire costs for 464 and 523 are allocated under labor. The allocation for non-labor and labor used the same allocation factor in the past so this will not affect the allocation.

Customer Contracts and Orders

Org Unit 464 - Customer Accounts, contributed 98% of the non-labor charges to FERC account 90351. The charges to this Org Unit were for payment to Seattle Public Utilities to support the joint call center, which is the customer contact point for billing information services for the Residential, Small General Service, and Medium General Service customers. The sum of the expenditures allocated represented 98% of the total expenditures for this account. Ratios were developed from this overall factor to compute the final class allocations as seen below in **Table 3.50**.

Table 3.50: Customer Contracts and Orders (FERC 90351)

	Allocation Factor	Total	Residential	Small	Medium	Large	High Demand
FERC 90351							
Labor							
341 North Customer Eng	C_R_S_M	$911,809	$814,772	$90,365	$6,671	$0	$0
352 South Customer Eng	C_R_S_M	$667,882	$596,805	$66,191	$4,887	$0	$0
430 CC Director's Office	C_ALL	$96,708	$86,379	$9,580	$707	$39	$2
463 Credit	C_R_S_M	$552,805	$493,974	$54,786	$4,045	$0	$0
464 Customer Accounts	C_R_S_M	$1,778,66	$1,589,379	$176,276	$13,014	$0	$0
Non-Labor							
341 North Customer Eng	C_R_S_M	$58,120	$51,935	$5,760	$425	$0	$0
352 South Customer Eng	C_R_S_M	$32,266	$28,832	$3,198	$236	$0	$0
430 CC Director's Office	C_ALL	$0	$0	$0	$0	$0	$0
464 Customer Accounts	C_R_S_M	$6,203,33	$5,543,165	$614,787	$45,387	$0	$0
Total Allocated		$10,301,5	$9,205,241	$1,020,943	$75,372	$39	$2
Overall Allocation Ratios			89.36%	9.91%	0.73%	0.00%	0.00%
Total FERC 90351		$10,516,4	$9,397,244	$1,042,238	$76,944	$40	$2
Meters			387,926	44,400	3,184	159	10
$2016/Meter			$24.22	$23.47	$24.17	$0.25	$0.23

Bill Revenue Accounting and Mailing

Expenditures from the seven Org Units shown in **Table 3.51** contributed over 98% of the charges to FERC account 90361. The non-labor expenditures were postage costs and supplies for mailing utility bills. Ratios were developed from this overall factor and applied to the total of $3,858,973 to compute the final class allocations.[11]

[11] For this Ferc Code, the total dollar amount is less than the labor and non-labor expenditures from the seven Org Units because there were approximately $20,000 in financial adjustments.

Table 3.51: Bill Revenue Accounting and Mailings: FERC 90361

	Allocation Factor	Total	Residential	Small	Medium	Large	High Demand
FERC 90361							
Labor							
341 North Customer Eng	BI_R_S_M	$0	$0	$0	$0	$0	$0
352 South Customer Eng	BI_R_S_M	$27,964	$24,740	$2,873	$351	$0	$0
431 Account Executives Office	BI_L_H	$7,564	$0	$0	$0	$7,132	$432
464 Customer Accounts	BI_R_S_M	$1,330,749	$1,177,359	$136,699	$16,691	$0	$0
543 General Accounting	BI_ALL	$411,862	$364,143	$42,279	$5,162	$261	$16
Non-Labor							
463 Credit	BI_ALL	$131,852	$116,575	$13,535	$1,653	$84	$5
464 Customer Accounts	BI_ALL	$1,324,428	$1,170,978	$135,958	$16,601	$839	$51
580 Office Supplies	BI_ALL	$419,067	$370,513	$43,019	$5,253	$266	$16
Total Allocated		$3,653,485	$3,224,309	$374,363	$45,711	$8,581	$520
Overall Allocation Ratios			88.25%	10.25%	1.25%	0.23%	0.01%
Total FERC 90361[12]		$3,858,973	$3,405,658	$395,419	$48,282	$9,064	$550
Meters			387,926	44,400	3,184	159	10
$2016/Meter			$8.78	$8.91	$15.17	$57.12	$53.22

Miscellaneous Customer Accounting Expenses

Expenditures from six Org Units shown in **Table 3.52** contributed 75% of the charges to FERC 90501. Ratios were developed from this overall factor and applied to the program code total of $996,439 to compute the final class allocations. In 2016, 24% of this FERC account is for org unit 000 – Financial Statement Org. This is allocated according to the allocation factor developed from the other Org Units shown in **Table 3.52.**

Supervision Expenses

FERC Program Code 90701 costs were directly assigned to the Residential class as seen in **Table 3.53.** FERC Program Code 90711, assigned to the commercial classes, was $0 for 2016.

Customer Assistance Expenses

Costs for FERC Program Code 90801, Customer Assistance Expenses –Residential, were directly assigned to the Residential class and costs for Program Code 90811, Customer Assistance – Commercial and Industrial, were allocated among other customer classes as indicated in **Table 3.54**.

[12] For FERC account 90361, there is a small difference (1.6%) between the Cognos and L22 values for org unit 464. Since the labor and non-labor are allocated differently for Org Unit 464, Cognos values are used to develop the allocation ratio but the L22 is used for the total for FERC 90361. The difference is small and will not significantly affect the allocation.

Table 3.52: Miscellaneous Customer Account Expenses (FERC 90501)

	Allocation Factor	Total	Residential	Small	Medium	Large	High Demand
FERC 90501							
Labor							
317 Bus Plang and Implementation	C_ALL	$2,203	$1,968	$218	$16	$1	$0
430 Customer	C_ALL	$453,79	$405,330	$44,955	$3,319	$182	$11
463 Credit	C_R_S_M	$2,368	$2,116	$235	$17	$0	$0
473 Technical	C_L_HD	$165,11	$0	$0	$0	$155,788	$9,324
580 Office Services	C_ALL	$10,465	$9,347	$1,037	$77	$4	$0
Non-Labor							
430 Customer Care	C_ALL	$0	$0	$0	$0	$0	$0
464 Customer	C_R_S_M	$114,73	$102,523	$11,371	$839	$0	$0
473 Technical	C_L_HD	$53	$0	$0	$0	$50	$3
Total Allocated		$748,73	$521,284	$57,815	$4,268	$156,025	$9,338
Overall Allocation			69.62%	7.72%	0.57%	20.84%	1.25%
Total FERC 90501		$996,43	$693,744	$76,942	$5,680	$207,644	$12,428
Meters			387,926	44,400	3,184	159	10
$2016/Meter			$1.79	$1.73	$1.78	$1,308.47	$1,203.31

Table 3.53: Supervision-Residential (FERC 90701)

	Allocation Factor	Total	Residential	Small	Medium	Large	High Demand
FERC 90701	DIRECT:	$553,123	$553,123	$0	$0	$0	$0
FERC 90711	C_S_M_L_H	$0	$0	$0	$0	$0	$0
Total FERC 90701 90711		$553,123	$553,123	$0	$0	$0	$0
Meters			387,926	44,400	3,184	159	10
$2016/Meter			$1.43	$0.00	$0.00	$0.00	$0.00

[13] The dollar amount for Org Unit 430 was taken from the L22 because it differed from Cognos. The L22 is not broken out by labor/non-labor so all the dollars for FERC Account 90501 for Org Unit 430 is allocated under labor. The same allocation factor is used for labor and non-labor for 430 so this will affect the allocation.

Table 3.54: Customer Assistance Expenses-Residential (FERC 90801) and Customer Assistance Expenses-Commercial and Industrial (FERC 90811)

	Allocation Factor	Total	Residential	Small	Medium	Large	High Demand
FERC 90801	DIRECT: RESID	$3,109,336	$3,109,336				
FERC 90811							
Labor							
341 North Customer Eng	C_S_M	$312,956	$0	$291,440	$21,516	$0	$0
352 South Customer Eng	C_S_M	$140,885	$0	$131,199	$9,686	$0	$0
430 Customer Care Director's Office	C_S_M_L_H	$132,953	$0	$123,319	$9,104	$500	$30
431 Account Executives	C_L_H	$25,488	$0	$0	$0	$24,049	$1,439
000 Financial Statement	C_S_M_L_H	$5,500	$0	$5,101	$377	$21	$1
Non-Labor							
487 Solutions Designs	C_S_M_L_H	$97,000	$0	$89,971	$6,642	$365	$22
Total Allocated		$714,783	$0	$641,031	$47,325	$24,935	$1,492
Overall Allocation Ratios			0.00%	89.68%	6.62%	3.49%	0.21%
Total FERC 90811		$717,747	$0	$643,689	$47,521	$25,039	$1,499
Total FERC 90801 & 90811		$3,827,083	$3,109,336	$643,689	$47,521	$25,039	$1,499
Meters			387,926	44,400	3,184	159	10
$2016/Meter			$8.02	$14.50	$14.93	$157.78	$145.10

Miscellaneous Customer Service and Information Expenses

Miscellaneous activities charging to FERC account 91001 include support for phone notifications of schools, hospitals, and customers on life support of outages, suburban cities support, and general power quality metering issues. The allocated Org Unit charges represent over 99% of the total charges to this account. Ratios were developed from this overall factor and applied to the program code total of $1,075,399 to compute the final class allocations. See **Table 3.55**.

Table 3.55: Miscellaneous Customer Service and Information Expenses (FERC 91001)

	Allocation Factor	Total	Residential	Small	Medium	Large	High Demand
FERC 91001							
Labor							
431 Account	C_ALL	$1,062,365	$948,901	$105,24	$7,770	$427	$26
Non-Labor							
430 Customer Care	C_R_S_M	$575	$513	$57	$4	$0	$0
431 Account	C_ALL	$9,490	$8,476	$940	$69	$4	$0
Total Allocated		$1,072,429	$957,891	$106,23	$7,843	$431	$26
Overall Allocation			89.32%	9.91%	0.73%	0.04%	0.00%
Total FERC 91001		$1,075,399	$960,544	$106,53	$7,865	$432	$26
Meters			387,926	44,400	3,184	159	10
$2016/Meter			$2.48	$2.40	$2.47	$2.72	$2.50

General Advertising Expenses

General advertising expense, FERC account 93010, is allocated based on the customer count allocation factors as indicated in **Table 3.56**.

Table 3.56: General Advertising (FERC 93010)

	Allocation Factor	Total	Residential	Small	Medium	Large	High Demand
FERC 93010	C_ALL	$16,796	$15,002	$1,664	$123	$7	$0
Meters			387,926	44,400	3,184	159	10
$2016/Meter			$0.04	$0.04	$0.04	$0.04	$0.04

Miscellaneous Service Revenues

These revenues were allocated to the customer classes from which the revenues were received, with the reconnection and field charges allocated on the basis of EUC_BAD_DEBT. Results are in **Table 3.57**.

Table 3.57: Miscellaneous Service Revenues (FERC 45110, 45130, 45131, and 45150)

	Allocation Factor	Total	Residential	Small	Medium	Large	High Demand
FERC 45110	C_S_M_L_H	-$159,612	$0	-$148,046	-$10,930	-$601	-$36
FERC 45130	DIRECT: RESID	-$1,825,904	-$1,825,904	$0	$0	$0	$0
FERC 45131	C_S_M_L_H	-$32,866	$0	-$30,484	-$2,251	-$124	-$7
FERC 45150	EUC_BAD_DEBT	-$387,977	$0	-$247,748	-$86,829	-$53,401	$0
Total 451XX		-$2,406,360	-$1,825,904	-$426,278	-$100,009	-$54,125	-$43
Meters			387,926	44,400	3,184	159	10
$2016/Meter			-$4.71	-$9.60	-$31.41	-$341.07	-$4.20

Tables 3.58 and **3.59** summarizes the derivation of the 2016 marginal customer service cost per meter by non-network and network customer classes, respectively. The tables sum individual per meter costs by FERC account for each customer class and then adjust them for customer service revenues per meter, derived in **Table 3.57**.

Table 3.58: 2016 Non-network Customer Service Costs per Meter by Customer Class

FERC #	Residential	Small	Medium	Large	High Demand
90101 and 90201	$9.34	$11.03	$27.85	$738.57	$738.57
90301 & 90401 & 90403	$15.59	$21.98	$107.43	$1,325.53	$0.00
90311	$7.09	$1.73	$1.78	$0.00	$0.00
90321	$10.46	$10.13	$10.43	$9.18	$8.44
90341	$3.44	$5.86	$117.55	$1,130.21	$20,384.60
90351	$24.22	$23.47	$24.17	$0.25	$0.23
90361	$8.78	$8.91	$15.17	$57.12	$53.22
90501	$1.79	$1.73	$1.78	$1,308.47	$1,203.31
90701 & 90711	$1.43	$0.00	$0.00	$0.00	$0.00
90801 & 90811	$8.02	$14.50	$14.93	$157.78	$145.10
91001	$2.48	$2.40	$2.47	$2.72	$2.50
93010	$0.04	$0.04	$0.04	$0.04	$0.04
Subtotal	**$92.66**	**$101.78**	**$323.60**	**$4,729.87**	**$22,536.00**
451XX	-$4.71	-$9.60	-$31.41	-$341.07	-$4.20
$2016 Cost per Meter	**$87.95**	**$92.18**	**$292.18**	**$4,388.80**	**$22,531.80**

Table 3.59: 2016 Network Customer Service Costs per Meter by Customer Class

FERC #	Residential	Small	Medium	Large
90101 & 90201	$16.63	$15.88	$19.90	$738.57
90301 & 90401 & 90403	$15.59	$21.98	$107.43	$1,325.53
90311	$7.09	$1.73	$1.78	$0.00
90321	$10.46	$10.13	$10.43	$9.18
90341	$3.44	$5.86	$117.55	$1,130.21
90351	$24.22	$23.47	$24.17	$0.25
90361	$8.78	$8.91	$15.17	$57.12
90501	$1.79	$1.73	$1.78	$1,308.47
90701 & 90711	$1.43	$0.00	$0.00	$0.00
90801 & 90811	$8.02	$14.50	$14.93	$157.78
91001	$2.48	$2.40	$2.47	$2.72
93010	$0.04	$0.04	$0.04	$0.04
Subtotal	**$99.95**	**$106.64**	**$315.65**	**$4,729.87**
451XX	-$4.71	-$9.60	-$31.41	-$341.07
$2016 Cost per Meter	**$95.24**	**$97.03**	**$284.24**	**$4,388.80**

Total Customer Service Costs

Table 3.60 shows total customer service costs by customer class in 2019 and 2020, which were derived by inflating 2016 per meter costs and then multiplying them by the projected number of meters.

Table 3.60: 2019 and 2020 Customer Service Costs by Customer Class

		Residential	**Small**	**Medium**	**Large**	**High Demand**
Non-network $2016 Costs per Meter		$87.95	$92.18	$292.18	$4,388.80	$22,531.80
Network $2016 Costs per Meter		$95.24	$97.03	$284.24	$4,388.80	
2019 Customer Costs				$2019 inflation adjustment =		1.07415
Total Non-network	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**
2019 Meters	441,973	397,159	42,021	2,682	102	9
$2019 Total Costs	$43,222,965	$37,522,041	$4,160,510	$841,739	$480,851	$217,823
Downtown Network	**Total**	**Residential**	**Small**	**Medium**	**Large**	
2019 Meters	27,253	23,315	3,312	561	65	
$2019 Total Costs	$3,208,154	$2,385,239	$345,208	$171,282	$306,425	
Total Service Territory	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**
$2019 Total Cost	$46,431,119	$39,907,280	$4,505,718	$1,013,022	$787,276	$217,823
2020 Customer Costs				$2020 inflation adjustment =		1.10146
Total Non-network	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**
2020 Meters	450,851	405,846	42,203	2,690	103	9
$2020 Total Costs	$45,189,318	$39,317,570	$4,284,764	$865,714	$497,910	$223,360
Downtown Network	**Total**	**Residential**	**Small**	**Medium**	**Large**	
2020 Meters	28,525	24,524	3,365	570	66	
$2020 Total Costs	$3,429,865	$2,572,712	$359,649	$178,455	$319,049	
Total Service Territory	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**
$2020 Total Cost	$48,619,183	$41,890,281	$4,644,413	$1,044,169	$816,959	$223,360

3.5.2 Meter Costs

Like service drops, there are many kinds of meters assigned to the different classes. Meter O&M costs are the costs of maintaining and testing the meters. Meter capital costs are the cost of the meters themselves and the labor and non-labor cost of installation. Meter and installation capital costs are annualized over an assumed 34 year economic life of the meters. This is consistent with the 2016 Seattle City Light Cost Accounting Depreciation Schedule[14]. **Table 3.61** summarizes the $2016 annualized capital and O&M costs per meter and shows the total costs of meters by customer class for 2019 and 2020.

Table 3.61: 2019 and 2020 Total Meter Costs

Non-network		**Residential**	**Small**	**Medium**	**Large**	**High Demand**
Annualized Capital Cost		$5,476,180	$838,966	$203,353	$27,350	$4,320
Number of Meters		367,813	41,210	2,656	98	10
$2016 Capital Cost per		$14.89	$20.36	$76.56	$278.62	$418.29
$2016 O&M Cost per		$4.13	$4.13	$4.13	$4,111.86	$4,111.86
Total $2016 Cost per Non-network Meter		$19.02	$24.49	$80.69	$4,390.48	$4,530.15
Network		**Residential**	**Small**	**Medium**	**Large**	**High Demand**
Annualized Capital Cost		$281,263	$102,234	$40,390	$17,371	
Number of Meters		20,113	3,189	528	61	
$2016 Capital Cost per		$13.98	$32.05	$76.56	$286.99	
$2016 O&M Cost per		$4.13	$4.13	$4.13	$4,111.86	
Total $2016 Cost per Network Meter		$18.12	$36.19	$80.69	$4,398.84	
2019 Meter Costs				**$2019 inflation adjustment =**		**1.07415**
Total Non-network	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**
2019 Number of Meters	441,973	397,159	42,021	2,682	102	9
2019 Total Costs	$9,978,248	$8,115,416	$1,105,532	$232,471	$481,034	$43,795
Total Network	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**
2019 Number of Meters	27,253	23,315	3,312	561	65	
2019 Total Costs	$938,252	$453,758	$128,742	$48,626	$307,126	
Total Service Territory	$10,916,500	$8,569,173	$1,234,274	$281,098	$788,160	$43,795
2020 Meter Costs				**$2020 inflation adjustment =**		**1.10146**
Total Non-network	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**
2020 Number of Meters	450,851	405,846	42,203	2,690	103	9
2020 Total Costs	$10,424,409	$8,503,760	$1,138,549	$239,092	$498,100	$44,908
Total Network	**Total**	**Residential**	**Small**	**Medium**	**Large**	
2020 Number of Meters	28,525	24,524	3,365	570	66	
2020 Total Costs	$993,992	$489,422	$134,128	$50,663	$319,779	
Total Service Territory	$11,418,400	$8,993,181	$1,272,677	$289,755	$817,879	$44,908

14 The 2016 Rate Case had meters having an economic life of 18 years and installation annualized over 40 years. This was inconsistent with the depreciation schedules provided by Cost Accounting but consistent with the economic life assumed in past rate cases that had not been updated to reflect the Cost Accounting Depreciation Schedules.

3.5.3 Total Customer Costs

Table 3.62 below combines the meter costs in **Table 3.61** with the customer service costs totals in **Table 3.60** to arrive at the total customer costs by customer class**.**

Table 3.62: 2019 and 2020 Total Customer Costs

2019						
Non-network	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**
2019 Customer Costs	\$43,222,965	\$37,522,041	\$4,160,510	\$841,739	\$480,851	\$217,823
2019 Meter Costs	\$9,978,248	\$3,945,132	\$843,431	\$200,929	\$398,668	\$51,857
Total	\$53,201,213	\$41,467,174	\$5,003,941	\$1,042,668	\$879,519	\$269,680
Network	**Total**	**Residential**	**Small**	**Medium**	**Large**	
2019 Customer Costs	\$3,208,154	\$2,385,239	\$345,208	\$171,282	\$306,425	
2019 Meter Costs	\$938,252	\$453,758	\$128,742	\$48,626	\$307,126	
Total	\$4,146,406	\$2,838,996	\$473,950	\$219,909	\$613,551	
2020						
Non-network	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**
2020 Customer Costs	\$45,189,318	\$39,317,570	\$4,284,764	\$865,714	\$497,910	\$223,360
2020 Meter Costs	\$10,424,409	\$8,503,760	\$1,138,549	\$239,092	\$498,100	\$44,908
Total	\$55,613,727	\$47,821,330	\$5,423,312	\$1,104,806	\$996,010	\$268,268
Network	**Total**	**Residential**	**Small**	**Medium**	**Large**	
2020 Customer Costs	\$3,429,865	\$2,572,712	\$359,649	\$178,455	\$319,049	
2020 Meter Costs	\$993,992	\$489,422	\$134,128	\$50,663	\$319,779	
Total	\$4,423,856	\$3,062,133	\$493,777	\$229,117	\$638,829	

3.6 Summary of Allocation Factors

Tables 3.63 and **3.64** summarize 2019 and 2020 Total Energy, Distribution and Customer Marginal Costs by customer class derived in Sections 3.3-3.5. **Tables 3.65** and **3.66** present allocation factors that were calculated using the information about total costs in **Tables 3.63** and **3.64**. These factors are used to allocate functionalized revenue requirements by customer class for 2019 and 2020.

Table 3.63: 2019 Total Energy, Distribution and Customer Costs by Customer Class

Total Service Territory	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Energy	$343,325,091	$116,577,092	$45,286,189	$86,264,659	$55,069,038	$38,479,753	$1,648,359
Distribution							
ISA Transmission	$54,243,572	$20,496,670	$7,485,304	$13,122,825	$8,088,679	$4,872,954	$177,140
Stations	$51,991,895	$19,444,242	$7,157,082	$12,663,434	$7,948,969	$4,610,567	$167,601
Wires & Related Equip.	$419,081,227	$163,319,277	$54,254,035	$98,306,706	$73,402,939	$28,757,876	$1,040,395
Transformers	$17,896,315	$4,325,330	$2,536,833	$7,672,243	$2,725,980	$578,228	$57,702
Streetlights							
Customer Costs	$57,347,619	$48,476,454	$5,739,993	$1,294,119	$1,575,436	$261,617	
Non-network	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Energy	$295,109,620	$113,366,753	$40,312,856	$68,408,849	$32,893,050	$38,479,753	$1,648,359
Distribution							
ISA Transmission	$46,897,888	$19,934,286	$6,663,801	$10,408,787	$4,840,920	$4,872,954	$177,140
Stations	$44,372,647	$18,860,914	$6,304,985	$9,848,320	$4,580,258	$4,610,567	$167,601
Wires & Related Equip.	$316,521,149	$153,109,076	$42,855,478	$61,932,857	$28,825,467	$28,757,876	$1,040,395
Transformers	$10,692,566	$3,825,047	$1,765,434	$3,710,364	$755,790	$578,228	$57,702
Streetlights							
Customer Costs	$53,201,213	$45,637,457	$5,266,042	$1,074,210	$961,886	$261,617	
Network	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Energy	$48,215,471	$3,210,339	$4,973,333	$17,855,810	$22,175,989		
Distribution							
ISA Transmission	$7,345,684	$562,384	$821,503	$2,714,038	$3,247,759		
Stations	$7,619,249	$583,328	$852,097	$2,815,113	$3,368,710		
Wires & Related Equip.	$102,560,079	$10,210,201	$11,398,556	$36,373,849	$44,577,472		
Transformers	$7,203,750	$500,283	$771,399	$3,961,878	$1,970,190		
Streetlights							
Customer Costs	$4,146,406	$2,838,996	$473,950	$219,909	$613,551		

Table 3.64: 2020 Total Energy, Distribution and Customer Costs by Customer Class

Total Service Territory	Total	Residential	Small	Medium	Large	High Demand	Lights
Energy	$368,267,807	$126,305,152	$48,252,154	$92,048,153	$58,783,738	$41,212,458	$1,666,151
Distribution							
ISA Transmission	$55,622,644	$21,076,740	$7,664,786	$13,435,708	$8,282,882	$4,992,965	$169,563
Stations	$53,315,581	$19,995,112	$7,328,836	$12,965,898	$8,141,186	$4,724,116	$160,433
Wires & Related Equip.	$430,740,360	$168,859,887	$55,582,902	$100,627,30	$75,195,260	$29,478,682	$996,320
Transformers	$18,244,037	$4,464,590	$2,575,877	$7,790,551	$2,770,601	$587,028	$55,390
Streetlights							
Customer Costs	$60,037,583	$50,883,463	$5,917,090	$1,333,924	$1,634,839	$268,268	
Non-network	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Energy	$316,603,469	$122,788,758	$42,943,334	$72,955,053	$35,037,714	$41,212,458	$1,666,151
Distribution							
ISA Transmission	$48,069,792	$20,492,021	$6,822,028	$10,651,085	$4,942,131	$4,992,965	$169,563
Stations	$45,481,449	$19,388,617	$6,454,692	$10,077,571	$4,676,020	$4,724,116	$160,433
Wires & Related Equip.	$325,399,278	$158,160,008	$43,912,814	$63,405,265	$29,446,189	$29,478,682	$996,320
Transformers	$10,904,534	$3,943,027	$1,791,471	$3,762,388	$765,230	$587,028	$55,390
Streetlights							
Customer Costs	$55,613,727	$47,821,330	$5,423,312	$1,104,806	$996,010	$268,268	
Network	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Energy	$51,664,338	$3,516,394	$5,308,820	$19,093,100	$23,746,023		
Distribution							
ISA Transmission	$7,552,851	$584,719	$842,758	$2,784,623	$3,340,751		
Stations	$7,834,131	$606,495	$874,144	$2,888,327	$3,465,166		
Wires & Related Equip.	$105,341,081	$10,699,879	$11,670,088	$37,222,043	$45,749,071		
Transformers	$7,339,502	$521,564	$784,406	$4,028,163	$2,005,370		
Streetlights							
Customer Costs	$4,423,856	$3,062,133	$493,777	$229,117	$638,829		

Table 3.65: 2019 Allocation Factors

Non-network	Total	Residential	Small	Medium	Large	High Demand	Lights
Energy	85.96%	33.02%	11.74%	19.93%	9.58%	11.21%	0.48%
Distribution							
ISA Transmission	86.46%	36.75%	12.28%	19.19%	8.92%	8.98%	0.33%
Stations	85.35%	36.28%	12.13%	18.94%	8.81%	8.87%	0.32%
Wires & Related Equip.	100.00%	48.37%	13.54%	19.57%	9.11%	9.09%	0.33%
Transformers	100.00%	35.77%	16.51%	34.70%	7.07%	5.41%	0.54%
Streetlights							100.00%
Customer Costs	92.77%	79.58%	9.18%	1.87%	1.68%	0.46%	
Utility Discount Program	81.24%	37.58%	10.93%	16.46%	7.72%	8.22%	0.33%
Network	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Energy	14.04%	0.94%	1.45%	5.20%	6.46%		
Distribution							
ISA Transmission	13.54%	1.04%	1.51%	5.00%	5.99%		
Stations	14.65%	1.12%	1.64%	5.41%	6.48%		
Wires & Related Equip.	100.00%	9.96%	11.11%	35.47%	43.46%		
Transformers	100.00%	6.94%	10.71%	55.00%	27.35%		
Streetlights							
Customer Costs	7.23%	4.95%	0.83%	0.38%	1.07%		
Utility Discount Program	18.76%	1.90%	2.04%	6.77%	8.05%		

Table 3.66: 2020 Allocation Factors

Non-network	Total	Residential	Small	Medium	Large	High Demand	Lights
Energy	85.97%	33.34%	11.66%	19.81%	9.51%	11.19%	0.45%
Distribution							
ISA Transmission	86.42%	36.84%	12.26%	19.15%	8.89%	8.98%	0.30%
Stations	85.31%	36.37%	12.11%	18.90%	8.77%	8.86%	0.30%
Wires & Related Equip.	100.00%	48.60%	13.50%	19.49%	9.05%	9.06%	0.31%
Transformers	100.00%	36.16%	16.43%	34.50%	7.02%	5.38%	0.51%
Streetlights							100.00%
Customer Costs	92.63%	79.65%	9.03%	1.84%	1.66%	0.45%	
Utility Discount Program	81.33%	37.78%	10.88%	16.42%	7.69%	8.24%	0.31%
Network	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Energy	14.03%	0.95%	1.44%	5.18%	6.45%		
Distribution							
ISA Transmission	13.58%	1.05%	1.52%	5.01%	6.01%		
Stations	14.69%	1.14%	1.64%	5.42%	6.50%		
Wires & Related Equip.	100.00%	10.16%	11.08%	35.33%	43.43%		
Transformers	100.00%	7.11%	10.69%	54.88%	27.32%		
Streetlights							
Customer Costs	7.37%	5.10%	0.82%	0.38%	1.06%		
Utility Discount Program	18.67%	1.93%	2.03%	6.72%	8.00%		

4 Cost Allocation

4.1 Initial Allocation

Tables 4.1 and **4.2** present the initial allocation of the functionalized revenue requirements by customer class for 2019 and 2020, respectively. The allocation factors shown in **Tables 3.65** and **3.66** for non-network and network customer classes are multiplied by the total service territory revenue requirement for each expense category from **Table 2.1** except for Wires and Related Equipment, and Transformers. For these two categories, the total network revenue requirements are first multiplied by 86% for 2019 and 87% for 2020 (the percent of total network load that is in the downtown network), and those results are then allocated to downtown network customer classes using the network allocation factors. The remaining revenue requirements for these two categories are then allocated to the non-network customers using the non-network allocation factors.

Table 4.3 shows the 2019 and 2020 forecasts for total non-network energy consumption by customer class broken out by City of Seattle and franchise groups. These franchise groups are determined by the franchise agreements each jurisdiction has with City Light. Shoreline and SeaTac have franchise agreements that include the same rate differential and franchise contract payment provisions, therefore they are grouped together for the purpose of allocating costs and calculating rates. Burien, Lake Forest Park and Tukwila have unique franchise agreements and are treated separately. Suburban areas that are not under franchise agreements with City Light are grouped with City customers. **Table 4.3** also shows non-network energy consumption by customer class for each group as a percent of total non-network energy consumption by customer class. These percentages are used to allocate the 2019 and 2020 non-network revenue requirements from **Tables 4.1** and **4.2** among customers in Seattle, Shoreline and SeaTac, Tukwila, Burien and Lake Forest Park. **Table 4.4** summarizes these results. Revenue requirements for Tukwila are broken out between energy and retail services because a separate franchise differential is applied to each component, per the franchise agreement.

In this rate case, revenue requirements are calculated by customer class net of franchise payments. The separation of energy consumption by franchise payment groups (Shoreline & SeaTac, Tukwila, Burien, and Lake Forest Park,) is done only to estimate rate differential revenue that is credited to the revenue requirement of City residential customers. For rate setting purposes, base rates will be calculated for all franchises together and then franchise differentials consistent with each franchise agreement with City Light will be applied to each rate component. This process is discussed in more detail in the Rate Design Report.

Table 4.1: 2019 Initial Allocation of Functionalized Revenue Requirements

Non-network	Total	Residential	Small	Medium	Large	High Demand	Lights
Total Energy	**$497,896,476**	**$191,267,594**	**$68,014,147**	**$115,416,518**	**$55,495,763**	**$64,921,413**	**$2,781,042**
Production	$131,287,168	$50,434,140	$17,934,220	$30,433,451	$14,633,326	$17,118,716	$733,315
Purchased Power	$260,289,354	$99,990,502	$35,556,304	$60,337,223	$29,011,967	$33,939,490	$1,453,868
Conservation	$50,524,456	$19,409,037	$6,901,792	$11,711,987	$5,631,478	$6,587,954	$282,209
Transmission-Long Distance	$55,795,497	$21,433,915	$7,621,832	$12,933,857	$6,218,991	$7,275,252	$311,650
Total Retail Services	**$342,443,412**	**$187,854,192**	**$42,064,405**	**$52,362,568**	**$23,675,708**	**$22,311,703**	**$14,174,836**
Distribution	$230,851,782	$99,727,487	$30,334,842	$46,600,983	$20,178,692	$19,912,460	$14,097,316
In Service Area Transmission	$16,050,360	$6,822,321	$2,280,623	$3,562,309	$1,656,759	$1,667,723	$60,624
Stations	$42,055,091	$17,875,821	$5,975,680	$9,333,949	$4,341,034	$4,369,760	$158,848
Wires & Related Equipment	$142,842,202	$69,096,291	$19,340,164	$27,949,556	$13,008,588	$12,978,085	$469,518
Transformers	$16,585,304	$5,933,054	$2,738,376	$5,755,169	$1,172,311	$896,893	$89,502
Streetlights	$13,318,825						$13,318,825
Customer Costs	$92,362,177	$79,230,805	$9,142,332	$1,864,928	$1,669,921	$454,191	
Utility Discount Program	$19,229,453	$8,895,899	$2,587,231	$3,896,657	$1,827,095	$1,945,051	$77,520
Total	**$840,339,888**	**$379,121,786**	**$110,078,551**	**$167,779,086**	**$79,171,471**	**$87,233,115**	**$16,955,878**
Network	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Total Energy	**$81,347,104**	**$5,416,348**	**$8,390,798**	**$30,125,568**	**$37,414,391**		
Production	$21,449,903	$1,428,202	$2,212,516	$7,943,620	$9,865,564		
Purchased Power	$42,526,481	$2,831,548	$4,386,525	$15,748,986	$19,559,423		
Conservation	$8,254,765	$549,628	$851,463	$3,057,017	$3,796,656		
Transmission-Long Distance	$9,115,956	$606,969	$940,293	$3,375,945	$4,192,748		
Total Retail Services	**$75,363,926**	**$11,124,742**	**$8,345,404**	**$27,150,898**	**$28,742,881**		
Distribution	$63,724,360	$5,746,955	$7,038,813	$25,165,634	$25,772,958		
In Service Area Transmission	$2,513,991	$192,470	$281,152	$928,854	$1,111,515		
Stations	$7,221,300	$552,861	$807,593	$2,668,082	$3,192,765		
Wires & Related Equipment	$41,593,781	$4,140,801	$4,622,745	$14,751,606	$18,078,629		
Transformers	$12,395,288	$860,823	$1,327,324	$6,817,092	$3,390,050		
Streetlights	$0						
Customer Costs	$7,198,541	$4,928,758	$822,821	$381,782	$1,065,180		
Utility Discount Program	$4,441,025	$449,029	$483,770	$1,603,483	$1,904,743		
Total	**$156,711,030**	**$16,541,090**	**$16,736,202**	**$57,276,466**	**$66,157,272**		
Total Service Territory	**$997,050,918**	**$395,662,876**	**$126,814,753**	**$225,055,552**	**$145,328,743**	**$87,233,115**	**$16,955,878**

Table 4.2: 2020 Initial Allocation of Functionalized Revenue Requirements

Non-network	Total	Residential	Small	Medium	Large	High Demand	Lights
Total Energy	**$517,681,236**	**$200,773,025**	**$70,217,039**	**$119,289,476**	**$57,290,488**	**$67,386,868**	**$2,724,339**
Production	$136,355,451	$52,882,922	$18,494,926	$31,420,436	$15,090,117	$17,749,469	$717,582
Purchased Power	$271,572,754	$105,324,434	$36,835,476	$62,578,609	$30,054,278	$35,350,784	$1,429,174
Conservation	$52,436,903	$20,336,676	$7,112,416	$12,083,055	$5,803,061	$6,825,742	$275,953
Transmission-Long Distance	$57,316,128	$22,228,993	$7,774,222	$13,207,376	$6,343,033	$7,460,874	$301,631
Total Retail Services	**$356,490,549**	**$195,767,329**	**$43,581,127**	**$54,507,107**	**$24,583,870**	**$23,277,610**	**$14,773,506**
Distribution	$240,625,449	$104,425,028	$31,520,813	$48,388,646	$20,901,347	$20,695,774	$14,693,841
ISA Transmission	$16,731,052	$7,132,402	$2,374,458	$3,707,190	$1,720,146	$1,737,839	$59,018
Stations	$43,409,592	$18,505,390	$6,160,656	$9,618,499	$4,463,009	$4,508,914	$153,125
Wires & Related Equip.	$149,165,618	$72,501,806	$20,129,983	$29,065,478	$13,498,367	$13,513,262	$456,721
Transformers	$17,382,505	$6,285,430	$2,855,716	$5,997,479	$1,219,825	$935,759	$88,296
Streetlights	$13,936,682						$13,936,682
Customer Costs	$94,900,625	$81,603,487	$9,254,473	$1,885,269	$1,699,616	$457,780	
Utility Discount Program	$20,964,476	$9,738,815	$2,805,841	$4,233,192	$1,982,906	$2,124,057	$79,665
Total	**$874,171,785**	**$396,540,354**	**$113,798,166**	**$173,796,584**	**$81,874,358**	**$90,664,479**	**$17,497,845**
Network	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Total Energy	**$84,476,832**	**$5,749,688**	**$8,680,501**	**$31,219,303**	**$38,827,340**		
Production	$22,250,906	$1,514,448	$2,286,414	$8,223,057	$10,226,987		
Purchased Power	$44,316,086	$3,016,255	$4,553,743	$16,377,476	$20,368,611		
Conservation	$8,556,817	$582,397	$879,264	$3,162,262	$3,932,894		
Transmission-Long Distance	$9,353,024	$636,588	$961,079	$3,456,508	$4,298,848		
Total Retail Services	**$80,148,166**	**$11,961,774**	**$8,830,914**	**$28,798,842**	**$30,556,636**		
Distribution	$67,785,747	$6,240,086	$7,466,243	$26,676,356	$27,403,063		
ISA Transmission	$2,628,827	$203,516	$293,328	$969,209	$1,162,773		
Stations	$7,477,256	$578,866	$834,323	$2,756,752	$3,307,314		
Wires & Related Equip.	$44,535,923	$4,523,676	$4,933,860	$15,736,672	$19,341,715		
Transformers	$13,143,741	$934,027	$1,404,731	$7,213,722	$3,591,260		
Streetlights							
Customer Costs	$7,548,977	$5,225,299	$842,593	$390,972	$1,090,113		
Utility Discount Program	$4,813,443	$496,389	$522,078	$1,731,514	$2,063,461		
Total	**$164,624,998**	**$17,711,463**	**$17,511,415**	**$60,018,144**	**$69,383,977**		
Total Service Territory	**$1,038,796,784**	**$414,251,817**	**$131,309,581**	**$233,814,728**	**$151,258,335**	**$90,664,479**	**$17,497,845**

Table 4.3: Percentage of Energy Consumption by Franchise Group 2019-2020

2019	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**
Total Non-network kWh						
City of Seattle	6,781,186	2,523,737	950,308	1,610,851	746,572	903,189
Shoreline & SeaTac	409,947	239,895	53,444	85,674	30,934	
Tukwila	432,027	59,599	26,952	98,194	99,528	147,754
Burien	283,980	179,474	46,695	46,305	11,506	
Lake Forest Park	70,090	58,050	5,948	6,092		
Percentage						
City of Seattle	85.01%	82.45%	87.72%	87.21%	84.02%	85.94%
Shoreline & SeaTac	5.14%	7.84%	4.93%	4.64%	3.48%	
Tukwila	5.42%	1.95%	2.49%	5.32%	11.20%	14.06%
Burien	3.56%	5.86%	4.31%	2.51%	1.29%	
Lake Forest Park	0.88%	1.90%	0.55%	0.33%		
2020	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**
Total Non-network kWh	7,936,953	3,076,933	1,072,069	1,826,575	877,334	1,040,484
City of Seattle	6,744,717	2,536,908	940,385	1,592,809	736,857	894,200
Shoreline & SeaTac	409,515	241,238	52,900	84,768	30,609	
Tukwila	428,532	59,932	26,677	97,156	98,483	146,284
Burien	283,899	180,479	46,219	45,816	11,385	
Lake Forest Park	70,290	58,375	5,888	6,027		
Percentage						
City of Seattle	84.98%	82.45%	87.72%	87.20%	83.99%	85.94%
Shoreline & SeaTac	5.16%	7.84%	4.93%	4.64%	3.49%	
Tukwila	5.40%	1.95%	2.49%	5.32%	11.23%	14.06%
Burien	3.58%	5.87%	4.31%	2.51%	1.30%	
Lake Forest Park	0.89%	1.90%	0.55%	0.33%		

Table 4.4:
2019 and 2020 Total Non-network Revenue Requirements Allocated by Jurisdiction

2019	Total	Residential	Small	Medium	Large	High Demand
Total Non-network	**$840,339,888**	**$379,121,786**	**$110,078,551**	**$167,779,086**	**$79,171,471**	**$87,233,115**
City of Seattle	$713,929,268	$312,603,890	$96,560,472	$146,318,475	$66,521,723	$74,968,830
Shoreline & SeaTac	$45,683,425	$29,714,665	$5,430,457	$7,782,000	$2,756,302	
Tukwila Energy	$26,895,733	$3,724,347	$1,692,079	$6,135,612	$6,216,258	$9,127,437
Tukwila Retail Services	$13,276,841	$3,657,881	$1,046,493	$2,783,626	$2,651,992	$3,136,849
Burien	$32,206,531	$22,230,634	$4,744,655	$4,206,047	$1,025,195	
Lake Forest Park	$8,348,090	$7,190,369	$604,395	$553,326		
2020	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**
Total Non-network	**$874,171,785**	**$396,540,354**	**$113,798,166**	**$173,796,584**	**$81,874,358**	**$90,664,479**
City of Seattle	$742,499,132	$326,944,593	$99,820,107	$151,553,979	$68,764,837	$77,917,771
Shoreline & SeaTac	$47,626,887	$31,089,599	$5,615,240	$8,065,564	$2,856,484	
Tukwila Energy	$27,907,994	$3,910,657	$1,747,283	$6,345,008	$6,430,985	$9,474,060
Tukwila Retail Services	$13,829,106	$3,813,156	$1,084,474	$2,899,234	$2,759,594	$3,272,648
Burien	$33,587,141	$23,259,273	$4,906,101	$4,359,309	$1,062,457	
Lake Forest Park	$8,721,526	$7,523,076	$624,961	$573,489		

4.2 Adjustments

4.2.1 Net Wholesale Revenue Credit

City Light sells surplus energy in the wholesale market and buys when deficit. On an annual basis, the utility is a net seller and the projected net wholesale revenues serve to reduce the revenue requirements. Per the 2019-2024 Strategic Plan Update, assumed net wholesale revenues (NWR) of $55 million in 2019 and $50 million and 2020. **Tables 4.5** and **4.6** show how this net wholesale revenue credit is allocated among customers in 2019 and 2020, respectively. We first calculate revenue requirements for each customer class in the City, Network and franchise groups as a percent of total revenue requirements and then multiply this percentage by the projected NWR.

Table 4.5: 2019 Net Wholesale Credit Allocation

Revenue Requirements	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
City of Seattle	$713,929,268	$312,603,890	$96,560,472	$146,318,475	$66,521,723	$74,968,830	$16,955,878
Shoreline & SeaTac	$45,683,425	$29,714,665	$5,430,457	$7,782,000	$2,756,302	$0	$0
Tukwila	$40,172,574	$7,382,228	$2,738,572	$8,919,238	$8,868,250	$12,264,285	$0
Burien	$32,206,531	$22,230,634	$4,744,655	$4,206,047	$1,025,195	$0	$0
Lake Forest Park	$8,348,090	$7,190,369	$604,395	$553,326	$0	$0	$0
Network	$156,711,030	$16,541,090	$16,736,202	$57,276,466	$66,157,272	$0	$0
Total Service Territory	**$997,050,918**	**$395,662,876**	**$126,814,753**	**$225,055,552**	**$145,328,743**	**$87,233,115**	**$16,955,878**
% of Total Service Territory Revenue Requirements	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
City of Seattle	71.60%	31.35%	9.68%	14.68%	6.67%	7.52%	1.70%
Shoreline & SeaTac	4.58%	2.98%	0.54%	0.78%	0.28%	0.00%	0.00%
Tukwila	4.03%	0.74%	0.27%	0.89%	0.89%	1.23%	0.00%
Burien	3.23%	2.23%	0.48%	0.42%	0.10%	0.00%	0.00%
Lake Forest Park	0.84%	0.72%	0.06%	0.06%	0.00%	0.00%	0.00%
Network	15.72%	1.66%	1.68%	5.74%	6.64%	0.00%	0.00%
Total Service Territory	100.00%	39.68%	12.72%	22.57%	14.58%	8.75%	1.70%
Net Wholesale Revenue Credit	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
City of Seattle	$39,382,251	$17,244,068	$5,326,534	$8,071,319	$3,669,516	$4,135,482	$935,332
Shoreline & SeaTac	$2,520,020	$1,639,141	$299,559	$429,276	$152,045	$0	$0
Tukwila	$2,216,027	$407,223	$151,067	$492,009	$489,196	$676,531	$0
Burien	$1,776,599	$1,226,301	$261,728	$232,017	$56,553	$0	$0
Lake Forest Park	$460,503	$396,640	$33,340	$30,523	$0	$0	$0
Network	$8,644,600	$912,451	$923,214	$3,159,523	$3,649,412	$0	$0
Total	**$55,000,000**	**$21,825,824**	**$6,995,442**	**$12,414,667**	**$8,016,723**	**$4,812,012**	**$935,332**

Table 4.6: 2020 Net Wholesale Credit Allocation

Revenue Requirements	Total	Residential	Small	Medium	Large	High Demand	Lights
City of Seattle	$742,499,132	$326,944,593	$99,820,107	$151,553,979	$68,764,837	$77,917,771	$17,497,845
Shoreline & SeaTac	$47,626,887	$31,089,599	$5,615,240	$8,065,564	$2,856,484	$0	$0
Tukwila	$41,737,100	$7,723,813	$2,831,757	$9,244,242	$9,190,580	$12,746,708	$0
Burien	$33,587,141	$23,259,273	$4,906,101	$4,359,309	$1,062,457	$0	$0
Lake Forest Park	$8,721,526	$7,523,076	$624,961	$573,489	$0	$0	$0
Network	$164,624,998	$17,711,463	$17,511,415	$60,018,144	$69,383,977	$0	$0
Total Service Territory	**$1,038,796,784**	**$414,251,817**	**$131,309,581**	**$233,814,728**	**$151,258,335**	**$90,664,479**	**$17,497,845**
% of Total Service Territory Revenue Requirements	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
City of Seattle	71.48%	31.47%	9.61%	14.59%	6.62%	7.50%	1.68%
Shoreline & SeaTac	4.58%	2.99%	0.54%	0.78%	0.27%	0.00%	0.00%
Tukwila	4.02%	0.74%	0.27%	0.89%	0.88%	1.23%	0.00%
Burien	3.23%	2.24%	0.47%	0.42%	0.10%	0.00%	0.00%
Lake Forest Park	0.84%	0.72%	0.06%	0.06%	0.00%	0.00%	0.00%
Network	15.85%	1.70%	1.69%	5.78%	6.68%	0.00%	0.00%
Total Service Territory	100.00%	39.88%	12.64%	22.51%	14.56%	8.73%	1.68%
Net Wholesale Revenue Credit	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
City of Seattle	$35,738,421	$15,736,696	$4,804,602	$7,294,689	$3,309,831	$3,750,386	$842,217
Shoreline & SeaTac	$2,292,406	$1,496,424	$270,276	$388,217	$137,490	$0	$0
Tukwila	$2,008,916	$371,767	$136,300	$444,949	$442,367	$613,532	$0
Burien	$1,616,637	$1,119,529	$236,143	$209,825	$51,139	$0	$0
Lake Forest Park	$419,790	$362,105	$30,081	$27,604	$0	$0	$0
Network	$7,923,831	$852,499	$842,870	$2,888,830	$3,339,632	$0	$0
Total	**$50,000,000**	**$19,939,021**	**$6,320,273**	**$11,254,113**	**$7,280,458**	**$4,363,918**	**$842,217**

4.2.2 Franchise Agreements

City Light has franchise agreements with five suburban jurisdictions (Burien, Lake Forest Park, SeaTac, Shoreline and Tukwila) according to which their residents pay higher electric rates than the City of Seattle customers. As previously noted, jurisdictions are grouped based on their franchise agreements with City Light. Other suburban areas without franchise agreements are treated as if they were City customers.

Per the terms of Shoreline, and SeaTac's franchise agreements with City Light, total revenue requirements (net of the NWR credit) for each customer class are increased by 8%. Burien and Lake Forest Park's franchise agreements with City Light specify revenue requirement (net of the NWR credit) be increased by 6% (LFP has an additional 2% municipal tax). Tukwila's franchise agreement calls for the total energy requirements (gross of the NWR credit) to be increased by 8% and the total retail services requirements (gross of the NWR credit) to be increased by 6%. The separation of Tukwila's NWR credit between energy and retail services is based on energy and retail services revenue requirements as a percent of total revenue requirements before the NWR credit. Revenues from these rate differentials are credited to City of Seattle residential customers. **Tables 4.7** and **4.8** present the calculations for these franchise-related adjustments to rates for 2019 and 2020.

Table 4.7: 2019 Franchise Adjustments

Shoreline and SeaTac	Total	Residential	Small	Medium	Large	High Demand
Total Revenue Requirement net of NWR credit	$43,163,405	$28,075,525	$5,130,899	$7,352,724	$2,604,257	$0
Adjustment (8%)	$3,453,072	$2,246,042	$410,472	$588,218	$208,341	$0
Total Adjustment	**$3,453,072**	**$2,246,042**	**$410,472**	**$588,218**	**$208,341**	**$0**
Tukwila	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**
Total Energy	$26,895,733	$3,724,347	$1,692,079	$6,135,612	$6,216,258	$9,127,437
Total Retail Services	$13,276,841	$3,657,881	$1,046,493	$2,783,626	$2,651,992	$3,136,849
Energy Adjustment (8%)	$2,151,659	$297,948	$135,366	$490,849	$497,301	$730,195
Retail Services Adjustment (6%)	$796,610	$219,473	$62,790	$167,018	$159,120	$188,211
Total Adjustment	**$2,948,269**	**$517,421**	**$198,156**	**$657,867**	**$656,420**	**$918,406**
Burien	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**
Total Revenue Requirement net of NWR credit	$30,429,932	$21,004,333	$4,482,927	$3,974,030	$968,643	$0
Adjustment (6%)	$1,825,796	$1,260,260	$268,976	$238,442	$58,119	$0
Total Adjustment	**$1,825,796**	**$1,260,260**	**$268,976**	**$238,442**	**$58,119**	**$0**
Lake Forest Park	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**
Total Revenue Requirement net of NWR credit	$7,887,587	$6,793,729	$571,055	$522,803	$0	$0
Adjustment (6%)	$473,255	$407,624	$34,263	$31,368	$0	$0
Total Adjustment	**$473,255**	**$407,624**	**$34,263**	**$31,368**	**$0**	**$0**
Credit to City of Seattle Residential	**$8,700,393**	**$8,700,393**				

Table 4.8: 2020 Franchise Adjustments

Shoreline and SeaTac	Total	Residential	Small	Medium	Large	High Demand
Total Revenue Requirement net of NWR credit	$45,334,481	$29,593,176	$5,344,964	$7,677,348	$2,718,994	$0
Adjustment (8%)	$3,626,758	$2,367,454	$427,597	$614,188	$217,520	$0
Total Adjustment	**$3,626,758**	**$2,367,454**	**$427,597**	**$614,188**	**$217,520**	**$0**
Tukwila	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**
Total Energy	$27,907,994	$3,910,657	$1,747,283	$6,345,008	$6,430,985	$9,474,060
Total Retail Services	$13,829,106	$3,813,156	$1,084,474	$2,899,234	$2,759,594	$3,272,648
Energy Adjustment (8%)	$2,232,640	$312,853	$139,783	$507,601	$514,479	$757,925
Retail Services Adjustment (6%)	$829,746	$228,789	$65,068	$173,954	$165,576	$196,359
Total Adjustment	**$3,062,386**	**$541,642**	**$204,851**	**$681,555**	**$680,054**	**$954,284**
Burien	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**
Total Revenue Requirement net of NWR credit	$31,970,504	$22,139,743	$4,669,958	$4,149,484	$1,011,319	$0
Adjustment (6%)	$1,918,230	$1,328,385	$280,197	$248,969	$60,679	$0
Total Adjustment	**$1,918,230**	**$1,328,385**	**$280,197**	**$248,969**	**$60,679**	**$0**
Lake Forest Park	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**
Total Revenue Requirement net of NWR credit	$8,301,736	$7,160,971	$594,880	$545,885	$0	$0
Adjustment (6%)	$498,104	$429,658	$35,693	$32,753	$0	$0
Total Adjustment	**$498,104**	**$429,658**	**$35,693**	**$32,753**	**$0**	**$0**
Credit to City of Seattle Residential	**$9,105,479**	**$9,105,479**				

4.2.3 Consolidation of Seattle Network and Non-network Residential and Small General Service Classes

The costs of service and allocation of revenue requirements include all network classes. However, per City policy, Residential and Small General Service customers do not have distinct network rate classes. One set of rates is established for all Residential and one set of rates for all Small General Service customers within the City of Seattle. Therefore, one of the final steps in the allocation process is to consolidate the revenue requirements and loads for the network and non-network customers for Residential and Small General Service. **Tables 4.9** and **4.10** show how the 2019 and 2020 revenue requirements are broken out by functionalized category for City of Seattle Residential and Small General Service customers. Note that the franchise differential revenue credited to City of Seattle residential customers is shown near the bottom of these tables.

Table 4.9: 2019 City of Seattle Residential and Small General Service Revenue Requirements

	Non-network		Network		Total	
City of Seattle	**Residential**	**Small**	**Residential**	**Small**	**Residential**	**Small**
Total Energy	**$157,709,201**	**$59,661,742**	**$5,416,348**	**$8,390,798**	**$163,125,549**	**$68,052,540**
Production	$41,585,340	$15,731,827	$1,428,202	$2,212,516	$43,013,543	$17,944,343
Purchased Power	$82,446,910	$31,189,850	$2,831,548	$4,386,525	$85,278,458	$35,576,375
Conservation	$16,003,672	$6,054,225	$549,628	$851,463	$16,553,300	$6,905,688
Transmission-Long Distance	$17,673,279	$6,685,841	$606,969	$940,293	$18,280,248	$7,626,134
Total Retail Services	**$154,894,689**	**$36,898,730**	**$11,124,742**	**$8,345,404**	**$166,019,431**	**$45,244,135**
Distribution	$82,230,042	$26,609,604	$5,746,955	$7,038,813	$87,976,997	$33,648,417
ISA Transmission	$5,625,327	$2,000,553	$192,470	$281,152	$5,817,798	$2,281,705
Stations	$14,739,462	$5,241,843	$552,861	$807,593	$15,292,323	$6,049,435
Wires & Related Equip.	$56,973,168	$16,965,116	$4,140,801	$4,622,745	$61,113,969	$21,587,860
Transformers	$4,892,084	$2,402,093	$860,823	$1,327,324	$5,752,907	$3,729,417
Streetlights	$0	$0	$0	$0	$0	$0
Customer Costs	$65,329,556	$8,019,617	$4,928,758	$822,821	$70,258,314	$8,842,439
Utility Discount Program	$7,335,091	$2,269,509	$449,029	$483,770	$7,784,120	$2,753,278
Subtotal	**$312,603,890**	**$96,560,472**	**$16,541,090**	**$16,736,202**	**$329,144,980**	**$113,296,674**
NWR Credit	-$17,244,068	-$5,326,534	-$912,451	-$923,214	-$18,156,519	-$6,249,748
Franchise Adjustment					-$8,700,393	
Total	**$295,359,822**	**$91,233,938**	**$15,628,639**	**$15,812,988**	**$302,288,068**	**$107,046,926**

Table 4.10: 2020 City of Seattle Residential and Small General Service Revenue Requirements

	Non-network		Network		Total	
City of Seattle	**Residential**	**Small**	**Residential**	**Small**	**Residential**	**Small**
Total Energy	**$165,535,876**	**$61,592,138**	**$5,749,688**	**$8,680,501**	**$171,285,564**	**$70,272,639**
Production	$43,601,578	$16,223,157	$1,514,448	$2,286,414	$45,116,026	$18,509,571
Purchased Power	$86,839,218	$32,310,900	$3,016,255	$4,553,743	$89,855,473	$36,864,643
Conservation	$16,767,439	$6,238,783	$582,397	$879,264	$17,349,836	$7,118,047
Transmission-Long Distance	$18,327,640	$6,819,299	$636,588	$961,079	$18,964,229	$7,780,378
Total Retail Services	**$161,408,717**	**$38,227,969**	**$11,961,774**	**$8,830,914**	**$173,370,491**	**$47,058,883**
Distribution	$86,097,664	$27,649,047	$6,240,086	$7,466,243	$92,337,750	$35,115,290
ISA Transmission	$5,880,613	$2,082,798	$203,516	$293,328	$6,084,128	$2,376,127
Stations	$15,257,558	$5,403,930	$578,866	$834,323	$15,836,424	$6,238,253
Wires & Related Equip.	$59,777,204	$17,657,377	$4,523,676	$4,933,860	$64,300,880	$22,591,237
Transformers	$5,182,290	$2,504,943	$934,027	$1,404,731	$6,116,318	$3,909,673
Streetlights	$0	$0	$0	$0	$0	$0
Customer Costs	$67,281,472	$8,117,727	$5,225,299	$842,593	$72,506,771	$8,960,321
Utility Discount Program	$8,029,581	$2,461,194	$496,389	$522,078	$8,525,970	$2,983,272
Subtotal	**$326,944,593**	**$99,820,107**	**$17,711,463**	**$17,511,415**	**$344,656,055**	**$117,331,522**
NWR Credit	-$15,736,696	-$4,804,602	-$852,499	-$842,870	-$16,589,195	-$5,647,472
Franchise Adjustment					-$9,105,479	
Total	**$311,207,896**	**$95,015,505**	**$16,858,964**	**$16,668,544**	**$318,961,381**	**$111,684,050**

4.3 Final Allocation

Tables 4.11 and **4.12** summarize the final allocation of the 2019 and 2020 revenue requirements for City, Network and Franchise Cities.

Table 4.11: Final Allocation of 2019 Revenue Requirements

Total Service Territory	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Total Energy	$579,243,580	$196,683,942	$76,404,945	$145,542,086	$92,910,153	$64,921,413	$2,781,042
Total Retail Services	$417,807,338	$198,978,934	$50,409,809	$79,513,466	$52,418,590	$22,311,703	$14,174,836
Subtotal	$997,050,918	$395,662,876	$126,814,753	$225,055,552	$145,328,743	$87,233,115	$16,955,878
NWR Credit	-$55,000,000	-$21,825,824	-$6,995,442	-$12,414,667	-$8,016,723	-$4,812,012	-$935,332
Franchise Adjustment	$0	-$4,269,046	$911,867	$1,515,894	$922,879	$918,406	$0
Total	**$942,050,918**	**$369,568,005**	**$120,731,179**	**$214,156,779**	**$138,234,900**	**$83,339,509**	**$16,020,547**
Load (MWh)	9,278,592	3,147,427	1,216,991	2,329,211	1,487,492	1,050,943	46,529
Average Rate ($/MWh)	**$101.53**	**$117.42**	**$99.20**	**$91.94**	**$92.93**	**$79.30**	**$344.31**
City of Seattle	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Total Energy	$437,035,544	$163,125,549	$68,052,540	$100,653,599	$46,628,839	$55,793,976	$2,781,042
Total Retail Services	$310,171,016	$166,019,431	$45,244,135	$45,664,876	$19,892,884	$19,174,854	$14,174,836
Subtotal	$747,206,560	$329,144,980	$113,296,674	$146,318,475	$66,521,723	$74,968,830	$16,955,878
NWR Credit	-$41,217,916	-$18,156,519	-$6,249,748	-$8,071,319	-$3,669,516	-$4,135,482	-$935,332
Franchise Adjustment	-$8,700,393	-$8,700,393					
Total	**$697,288,252**	**$302,288,068**	**$107,046,926**	**$138,247,156**	**$62,852,207**	**$70,833,348**	**$16,020,547**
Load (MWh)	7,001,502	2,610,410	1,083,952	1,610,851	746,572	903,189	46,529
Average Rate ($/MWh)	**$99.59**	**$115.80**	**$98.76**	**$85.82**	**$84.19**	**$78.43**	**$344.31**
Network	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Total Energy	$67,539,959			$30,125,568	$37,414,391		
Total Retail Services	$55,893,780			$27,150,898	$28,742,881		
Subtotal	$123,433,738			$57,276,466	$66,157,272		
NWR Credit	-$6,808,936			-$3,159,523	-$3,649,412		
Franchise Adjustment							
Total	**$116,624,803**			**$54,116,943**	**$62,507,860**		
Load (MWh)	1,081,047			482,096	598,951		
Average Rate ($/MWh)	**$107.88**			**$112.25**	**$104.36**		
Franchise Cities	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Total Energy	$74,668,077	$33,558,393	$8,352,405	$14,762,919	$8,866,924	$9,127,437	
Total Retail Services	$51,742,543	$32,959,503	$5,165,674	$6,697,692	$3,782,824	$3,136,849	
Subtotal	$126,410,620	$66,517,896	$13,518,079	$21,460,611	$12,649,748	$12,264,285	
NWR Credit	-$6,973,148	-$3,669,305	-$745,693	-$1,183,825	-$697,794	-$676,531	
Franchise Adjustment	$8,700,393	$4,431,346	$911,867	$1,515,894	$922,879	$918,406	
Total	**$128,137,864**	**$67,279,937**	**$13,684,252**	**$21,792,681**	**$12,874,833**	**$12,506,160**	
Load (MWh)	1,196,043	537,017	133,039	236,264	141,968	147,754	
Average Rate ($/MWh)	**$107.13**	**$125.28**	**$102.86**	**$92.24**	**$90.69**	**$84.64**	

Table 4.12: Final Allocation of 2020 Revenue Requirements

Total Service Territory	Total	Residential	Small	Medium	Large	High Demand	Lights
Total Energy	$602,158,068	$206,522,713	$78,897,540	$150,508,779	$96,117,829	$67,386,868	$2,724,339
Total Retail Services	$436,638,715	$207,729,104	$52,412,041	$83,305,949	$55,140,506	$23,277,610	$14,773,506
Subtotal	$1,038,796,784	$414,251,817	$131,309,581	$233,814,728	$151,258,335	$90,664,479	$17,497,845
NWR Credit	-$50,000,000	-$19,939,021	-$6,320,273	-$11,254,113	-$7,280,458	-$4,363,918	-$842,217
Franchise Adjustment	$0	-$4,438,340	$948,338	$1,577,465	$958,253	$954,284	$0
Total	**$988,796,784**	**$389,874,456**	**$125,937,646**	**$224,138,080**	**$144,936,129**	**$87,254,844**	**$16,655,628**
Load (MWh)	9,230,139	3,165,052	1,204,596	2,304,584	1,471,865	1,040,484	43,558
Average Rate ($/MWh)	**$107.13**	**$123.18**	**$104.55**	**$97.26**	**$98.47**	**$83.86**	**$382.38**

City of Seattle	Total	Residential	Small	Medium	Large	High Demand	Lights
Total Energy	$454,335,355	$171,285,564	$70,272,639	$104,022,729	$48,117,276	$57,912,808	$2,724,339
Total Retail Services	$323,386,654	$173,370,491	$47,058,883	$47,531,251	$20,647,561	$20,004,963	$14,773,506
Subtotal	$777,722,009	$344,656,055	$117,331,522	$151,553,979	$68,764,837	$77,917,771	$17,497,845
NWR Credit	-$37,433,790	-$16,589,195	-$5,647,472	-$7,294,689	-$3,309,831	-$3,750,386	-$842,217
Franchise Adjustment	-$9,105,479	-$9,105,479					
Total	**$731,182,741**	**$318,961,381**	**$111,684,050**	**$144,259,291**	**$65,455,006**	**$74,167,385**	**$16,655,628**
Load (MWh)	6,965,364	2,625,028	1,072,912	1,592,809	736,857	894,200	43,558
Average Rate ($/MWh)	**$104.97**	**$121.51**	**$104.09**	**$90.57**	**$88.83**	**$82.94**	**$382.38**

Network	Total	Residential	Small	Medium	Large	High Demand	Lights
Total Energy	$70,046,643			$31,219,303	$38,827,340		
Total Retail Services	$59,355,478			$28,798,842	$30,556,636		
Subtotal	$129,402,121			$60,018,144	$69,383,977		
NWR Credit	-$6,228,462			-$2,888,830	-$3,339,632		
Franchise Adjustment	$0						
Total	**$123,173,659**			**$57,129,314**	**$66,044,345**		
Load (MWh)	1,072,540			478,009	594,531		
Average Rate ($/MWh)	**$114.84**			**$119.52**	**$111.09**		

Franchise Cities	Total	Residential	Small	Medium	Large	High Demand	Lights
Total Energy	$77,776,070	$35,237,149	$8,624,901	$15,266,748	$9,173,212	$9,474,060	
Total Retail Services	$53,896,583	$34,358,612	$5,353,158	$6,975,856	$3,936,309	$3,272,648	
Subtotal	$131,672,653	$69,595,761	$13,978,059	$22,242,604	$13,109,521	$12,746,708	
NWR Credit	-$6,337,748	-$3,349,826	-$672,800	-$1,070,595	-$630,995	-$613,532	
Franchise Adjustment	$9,105,479	$4,667,139	$948,338	$1,577,465	$958,253	$954,284	
Total	**$134,440,384**	**$70,913,075**	**$14,253,597**	**$22,749,474**	**$13,436,779**	**$13,087,459**	
Load (MWh)	1,192,236	540,024	131,684	233,766	140,477	146,284	
Average Rate ($/MWh)	**$112.76**	**$131.31**	**$108.24**	**$97.32**	**$95.65**	**$89.47**	

4.4 Average Rate Increases in 2019 and 2020 by Rate Class

Tables 4.13 – 4.15 present the average rates by rate class for 2018-2020. The average rate is derived by dividing each rate class' revenue requirement by its forecast load. **Tables 4.16** and **4.17** show the average rate increases for each rate class in 2019 and 2020.

Table 4.13: 2018 Average Rates by Rate Class (Strategic Plan)

	Total	Residential	Small	Medium	Large	High Demand	Lights
All areas	$95.97	$110.19	$95.04	$87.05	$89.10	$74.89	$301.40
Non-Network	$95.23	$110.19	$95.04	$82.74	$81.73	$74.89	$301.40
Network	$101.61			$103.56	$100.04		

Table 4.14: 2019 Average Rates by Rate Class

	Total	Residential	Small	Medium	Large	High Demand	Lights
All areas	$101.53	$117.42	$99.20	$91.94	$92.93	$79.30	$344.31
Non-Network	$100.69	$117.42	$99.20	$86.64	$85.23	$79.30	$344.31
Network	$107.88			$112.25	$104.36		

Table 4.15: 2020 Average Rates by Rate Class

	Total	Residential	Small	Medium	Large	High Demand	Lights
All areas	$107.13	$123.18	$104.55	$97.26	$98.47	$83.86	$382.38
Non-Network	$106.11	$123.18	$104.55	$91.43	$89.92	$83.86	$382.38
Network	$114.84			$119.52	$111.09		

Table 4.16: 2019 Average Rate Increases by Rate Class

	Total	Residential	Small	Medium	Large	High Demand	Lights
All areas	5.8%	6.6%	4.4%	5.6%	4.3%	5.9%	14.2%
Non-Network	5.7%	6.6%	4.4%	4.7%	4.3%	5.9%	14.2%
Network	6.2%			8.4%	4.3%		

Table 4.17: 2020 Average Rate Increases by Rate Class

	Total	Residential	Small	Medium	Large	High Demand	Lights
All areas	5.5%	4.9%	5.4%	5.8%	6.0%	5.8%	11.1%
Non-Network	5.4%	4.9%	5.4%	5.5%	5.5%	5.8%	11.1%
Network	6.5%			6.5%	6.4%		

Appendix A

The capital investments in generation, transmission, and distribution equipment and facilities provide service for an extended period of time. Instead of charging all the capital costs in the first year of operation, the costs are spread (or annualized) over the economic life of the capital asset. The process of converting the total initial cost of an asset to a series of annual costs is referred to as annualization (the calculation of annual carrying charges). The formula used in the calculation of the annual charges is shown below.

$$AC = k\left[\frac{r(1+r)^n}{(1+r)^n - 1}\right]$$

where: AC= annualized cost, r=real discount rate, k=investment (initial capital cost) and n=asset life in years,

This formula assumes that the annual costs occur at the end of each year. If costs are assumed to occur at the beginning of each year, they must be divided by (1+r). We define annualization factor (AF) for the costs incurred at the end of each year as:

$$AF_{end\ year} = \left[\frac{r(1+r)^n}{(1+r)^n - 1}\right]$$

And we define the annualization factor (AF) for the costs incurred at the beginning of each year as:

$$AF_{beg\ year} = \left[\frac{r(1+r)^{n-1}}{(1+r)^n - 1}\right]$$

In our analysis we assume that the costs are incurred in the mid-year and compute the annualization factors as an average of $AF_{end\ year}$ and $AF_{beg\ year}$, except for meters and service drops where we assume costs incur at year-end and use annualization factor $AF_{end\ year}$. The table below shows the asset lives assumed for the equipment and facilities used in this study and the corresponding annualization factors based on a three percent interest rate.[15]

Assumed Asset Lives and Annualization Factors

Functional Category	Annual Depreciation Rate	Years of Useful Life	Real Discount Rate	Annualization Factor
In-Service Area Transmission	2.33%	43	3.00%	0.04170
Substations	2.59%	39	3.00%	0.04384
Non-network Wires and Related Equipment	3.14%	32	3.00%	0.04905
Network Wires and Related Equipment	3.14%	32	3.00%	0.04905
Transformers	3.08%	32	3.00%	0.04905
Meters	2.92%	34	3.00%	0.04732
Service Drops	2.92%	34	3.00%	0.04732

[15] Asset lives are based on 2016 asset depreciation schedules prepared by Seattle City Light's Cost Accounting Unit.

Appendix B

This table illustrates how 2019 rates were calculated for the High Demand City customer class by aggregating data from the relevant sections of the COSACAR and Revenue Requirements Analysis.

Example: Average Rate for High Demand-City Customer Class for 2019							
		A	B	C	D	E	F	G
	MC Table	HD MC	Total MC[2,3]	MC Share (A/B)	Total Op. Cost Rev Req (Table 4.1)	HD Share of RR (C x D)	HD-City Load Share (Table 4.3)	HD-City Share of RR (E x F)
Energy	Table 3.16	$ 38,479,753	$ 343,325,091	11.208%	$ 579,243,580	$ 64,921,413	85.9408%	$ 55,793,976
ISA Transmission	Table 3.20	$ 4,872,954	$ 54,243,572	8.983%	$ 18,564,350	$ 1,667,723	85.9408%	$ 1,433,254
Stations	Table 3.24	$ 4,610,567	$ 51,991,895	8.868%	$ 49,276,392	$ 4,369,760	85.9408%	$ 3,755,407
Wires and Related Equip.[1]	Table 3.32	$ 28,757,876	$ 316,521,149	9.086%	$ 142,842,202	$ 12,978,085	85.9408%	$ 11,153,469
Transformers[1]	Table 3.42	$ 578,228	$ 10,692,566	5.408%	$ 16,585,304	$ 896,893	85.9408%	$ 770,797
Customer Costs	Table 3.63	$ 261,617	$ 57,347,619	0.456%	$ 99,560,718	$ 454,191	85.9408%	$ 390,336
Low Income Assistance[3]				8.217%	$ 23,670,478	$ 1,945,051	85.9408%	$ 1,671,592
Total Rev. Req. before NWR credit								$ 74,968,830
Less NWR credit (Table 4.5)[4]								-4,135,482
Total Class 2019 Revenue Requirement								$ 70,833,348
2019 Class Load in MWh (Table 4.11)								903,189
Average rate in $/MWh (class rev req / class load)								$ 78.4259
Average rate in $/kWh								$ 0.0784

(1) The Operating Cost Revenue Requirement from Table 4.1 for these items equals the grand total less the Downtown network portion of Network revenue requirements

(2) Total Marginal Cost for just Non-network for Wires and Related Equipment and Transformers

(3) HD MC Share % represents HD share of Total Marginal Costs

(4) Net Wholesale Revenue Credits are allocated based on share of Revenue Requirements allocated by Marginal Cost Shares.

The High Demand Share for Seattle is from Table 4.9 (7.52%)