Cost of Service and Cost Allocation Report

Adopted 2017-2018 Rates

October 10, 2016

Seattle City Light

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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 2016-2018.

Table E.1: Unbundled Revenue Requirement Summary

$M	2016[1]	2017	2017 vs. 2016	2018	2018 vs. 2017
Energy	$547.7	$564.2	$16.5	$587.7	$23.5
Retail Services	$340.8	$364.4	$23.6	$392.1	$27.7
Net Wholesale Revenue Credit	($60.0)	($60.0)	$0.0	($60.0)	$0.0
Total	**$828.5**	**$868.5**	**$40.0**	**$919.8**	**$51.2**

Note that the revenue requirement shown here is higher than the revenue requirement found in the RRA because the RRA treats rate discounts as an expense for unbundling purposes. Table 2.1 in chapter 2 of this report shows the relationship between the unbundled revenue requirement and the RRA revenue requirement. The 2017 and 2018 increases in the unbundled revenue requirement are driven by both energy costs and retail service costs. Retail service costs increased more than energy costs both as a percentage and in absolute terms.

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

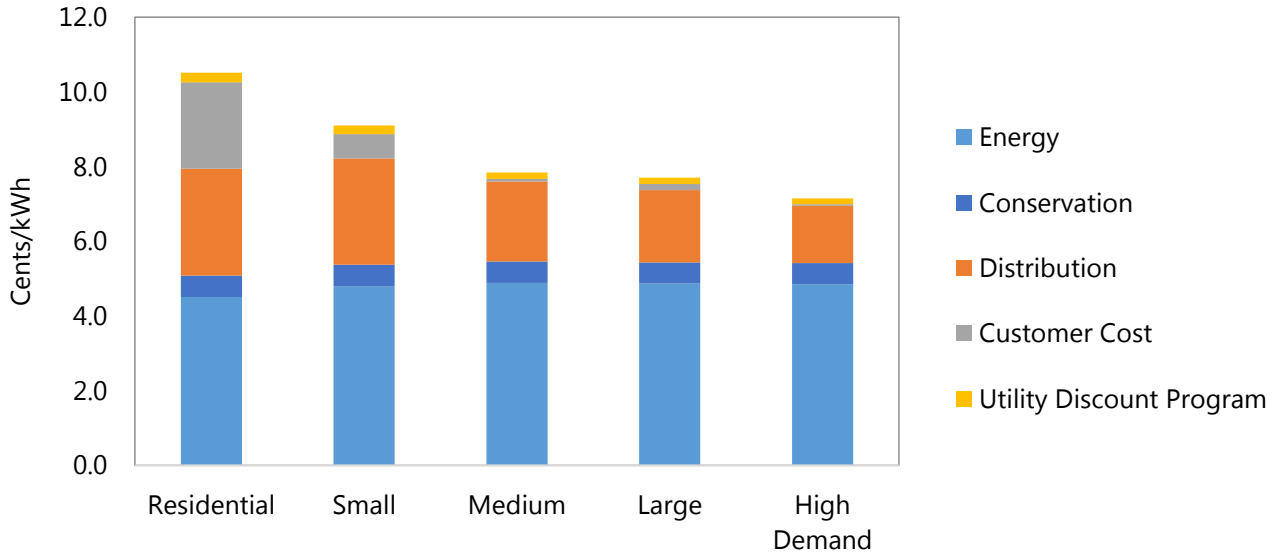
	Revenue Requirement		Percentage	
Customer Class	**2017**	**2018**	**2017**	**2018**
Residential	$ 332,850,329	$ 351,000,554	38%	38%
Small	$ 109,573,676	$ 116,121,892	13%	13%
Medium	$ 200,530,216	$ 212,883,091	23%	23%
Large	$ 131,784,610	$ 140,039,274	15%	15%
High Demand	$ 78,730,322	$ 83,734,199	9%	9%
Lights	$ 15,069,191	$ 15,996,231	2%	2%
Total	**$ 868,538,343**	**$ 919,775,241**	**100%**	**100%**

[1] From 2016 Adopted Cost of Service and Cost Allocation Report.

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. **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: 2017 Average Rates for City Customers



Changes to Average Rates

The below table summarizes the changes to the average rates for 2017 and 2018.

Table E.3: Summary of Average Rate Changes

2017	Total	Residential	Small	Medium	Large	High Demand
All areas	5.6%	5.0%	7.3%	5.5%	4.9%	6.9%
City of Seattle	5.9%	5.2%	7.3%	6.8%	5.7%	6.7%
Downtown Network	3.8%			3.8%	4.2%	
Franchise Cities	5.9%	4.5%	7.8%	6.8%	5.4%	7.8%
2018	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**
All areas	5.6%	5.7%	5.5%	5.6%	5.7%	5.6%
City of Seattle	5.6%	5.7%	5.5%	5.5%	5.5%	5.7%
Downtown Network	6.0%			6.0%	6.0%	
Franchise Cities	5.5%	5.7%	5.4%	5.5%	5.4%	5.6%

2017 highlights

- Downtown network rate increases are lower than other customer groups because network distribution costs increased less than non-network distribution costs relative to the previous rate case. Network average rates remain 20% to 25% higher than non-network rates.
- Shifts in meter counts and consumption patterns for individual customer classes and jurisdictions account for other variances in rate changes.

2018 highlights

- Downtown network increases are slightly higher than those of other customer classes because network distribution costs increased slightly more than non-network distribution costs relative to 2017.
- In general, 2018 rate increases for all customer classes are closer to the average for the system because the major consumption pattern differences were accounted for in 2017 rates.

Streetlights

- The average monthly streetlight charge per fixture is rising slowly due to increases in capital, O&M and energy costs.
- Despite increases to the average cost per fixture, the General Fund streetlight bill (which represents about 85% of the streetlights load) remains relatively stable because increasing rates are offset by the transition to lower cost lights as part of the LED Conversion Program.

Table E.4: 2017-2018 Streetlight Rate Increases

	2016	2017	2017 vs. 2016, %	2018	2018 vs. 2017, %
Streetlight Average Monthly Rate per Fixture	$14.26	$14.77	4%	$15.68	6%
Annual General Fund Streetlight Bill ($M)	$11.79	$11.47	-3%	$11.98	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 2015-2016 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 2017 and 2018 revenue requirement among customer classes.

2. Functionalization

This section describes how the revenue requirement is assigned to functionalized categories such as energy, distribution, customer service 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

A new approach, based on cash inflows and outflows, was used to unbundle the 2017-2018 revenue requirement. The new cash flow approach replaces the income statement-based allocation methodology that has been in use since the 1997-1998 rate review. Functionalizing revenue requirements using cash flow categories is the preferred method because it is consistent with the revenue requirement, which is also based on cash flows. The primary difference between the two methodologies is the exclusion of depreciation and amortization expenses and the inclusion of principal payments on debt under the cash flow approach. Models for both methodologies were run in parallel for the current rate case with the cash flow approach having no material impact on the unbundled revenue requirements. **Table 2.1** summarizes the functionalized revenue requirements for 2017 and 2018.

Table 2.1: Summary of Unbundled Revenue Requirements for 2017 and 2018

$ Millions	**2017**	**2018**
Total Energy	**$564.0**	**$587.7**
Power	445.9	463.1
Conservation	53.9	57.7
Transmission-Long Distance	64.2	66.9
Total Retail Services	**$364.5**	**$392.1**
Total Distribution	272.3	294.4
Transmission-In Service Area	16.7	18.0
Stations	45.3	48.1
Wires and Related Equipment	158.6	172.5
non-network	*116.6*	*126.8*
network	*42.0*	*45.7*
Transformers	25.1	27.3
non-network	*12.6*	*13.8*
network	*12.5*	*13.5*
Meters[2]	14.9	15.8
Streetlights/Floodlights	11.7	12.6
Customer Accounts & Services	71.3	75.6
Rate Discounts (UDP)	21.0	22.1
Subtotal	**$928.5**	**$979.8**
Net Wholesale Revenue Credit	-$60.0	-$60.0
Unbundled Revenue Requirement	**$868.5**	**$919.8**
Rate Discounts	-$16.9	-$17.9
Revenue Requirement (Strategic Plan)	$851.7	$901.9

[2] Note that meter costs are categorized as customer costs in the Cost Allocation process, which is described in section 3.5.

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 2017 and 2018. Each functional category is discussed individually in the following sections.

Table 2.2: Unbundled Revenue Requirements 2017-2018

Functions	**2017**		**2018**	
	Dollars	**$/MWh**	**Dollars**	**$/MWh**
ENERGY				
Power				
Direct Cash Outflows (Inflows):				
Generation O&M	49,465,339		53,414,887	
Long-Term Purchased Power	230,924,695		235,334,457	
Power-Related Wholesale Purchases	2,349,996		2,350,000	
Article 49 Sales to Pend Oreille County	(2,061,552)		(2,110,411)	
Sales from Priest Rapids	(2,326,968)		(2,190,140)	
Power-Related Wholesale Sales	(6,378,962)		(5,608,994)	
Subtotal	271,972,548		281,189,799	
Indirect Cash Outflows (Inflows):				
Debt Service	35,285,020		37,872,191	
Administration and General	21,691,954		22,856,922	
Taxes and Payments in Lieu of Taxes:				
Revenue Taxes	44,291,682		45,040,305	
Whatcom County Contract Payments	1,075,834		1,100,763	
Pend Oreille County Contract Payments	1,827,469		1,883,243	
Concrete School District Payments	30,000		30,000	
Subtotal	47,224,985		48,054,311	
Cost of Capital	27,826,504		30,027,563	
Risk Management Premium	41,894,473		43,124,074	
Total Power	**445,895,485**	**$47.27**	**463,124,860**	**$48.98**
Conservation				
Direct Cash Outflows (Inflows):				
Conservation	8,908,130		9,418,577	
Operating Fees (Lighting Lab)	(300,000)		(300,000)	
GreenUp and Community Solar Retail Sales	(1,534,974)		(1,571,420)	
Subtotal	7,073,156		7,547,157	

(Table 2.2 continued, page 2)

Functions	2017		2018	
	Dollars	$/MWh	Dollars	$/MWh
Indirect Cash Outflows (Inflows):				
Debt Service	31,630,628		33,842,725	
Administration and General	1,944,727		2,049,168	
Taxes	4,920,579		5,196,715	
Cost of Capital	8,377,170		9,039,799	
Total Conservation	**53,946,261**	**$5.72**	**57,675,565**	**$6.10**
Transmission-Long Distance				
Direct Cash Outflows (Inflows):				
Transmission O&M	6,792,942		7,160,045	
Wheeling	43,841,090		45,335,858	
Transmission Services	(3,415,980)		(3,420,145)	
Transmission Attachments & Cell Sites	(819,752)		(827,950)	
Subtotal	46,398,300		48,247,808	
Indirect Cash Outflows (Inflows):				
Debt Service	4,761,486		5,101,343	
Administration and General	3,514,570		3,703,320	
Taxes				
Oregon Tax on 3rd AC Intertie	245,000		245,000	
Revenue Taxes	6,918,251		7,078,124	
Subtotal	7,163,251		7,323,124	
Cost of Capital	2,322,182		2,505,865	
Total Transmission-Long Distance	**64,159,788**	**$6.80**	**66,881,460**	**$7.07**
TOTAL ENERGY	**564,001,533**	**$59.80**	**587,681,885**	**$62.15**
RETAIL SERVICES				
Transmission-In Service Area				
Direct Cash Outflows (Inflows):				
Transmission O&M	5,235,463		5,518,398	
Transmission Attachments & Cell Sites	(647,812)		(654,290)	
Subtotal	4,587,651		4,864,108	
Indirect Cash Outflows (Inflows):				
Capital Contributions and Grant Receipts	(1,103,908)		(1,106,777)	
Debt Service	5,359,327		5,748,018	
Administration and General	2,708,753		2,854,227	
Taxes	1,613,008		1,747,071	
Cost of Capital	3,566,773		3,848,903	
Total Transmission-In Service Area	**16,731,605**	**$1.77**	**17,955,549**	**$1.90**

(Table 2.2 continued, page 3)

Functions	2017		2018	
	Dollars	$/MWh	Dollars	$/MWh
Distribution-Stations				
Direct Cash Outflows (Inflows):				
Distribution O&M-Stations	16,504,130		17,449,844	
Gain on Sale of Distribution Assets*	0		0	
Subtotal	16,504,130		17,449,844	
Indirect Cash Outflows (Inflows):				
Capital Contributions and Grant Receipts	(1,885,967)		(1,890,869)	
Debt Service	11,450,519		12,252,088	
Administration and General	11,784,324		12,417,201	
Taxes	4,252,522		4,516,831	
Cost of Capital	3,152,266		3,401,608	
Total Distribution-Stations	**45,257,794**	**$4.80**	**48,146,705**	**$5.09**
Distribution-Wires and Related Equipment				
Direct Cash Outflows (Inflows):				
Distribution O&M-Wires and Related Equipment	41,076,702		43,430,464	
Property Rental Receipts	(2,628,785)		(2,655,072)	
Damage Receipts	(1,676,449)		(1,693,214)	
Other O&M Receipts	(7,525,767)		(7,604,025)	
Construction (Installation) Receipts	(5,399)		(5,453)	
Pole Attachment Receipts	(2,382,628)		(2,406,454)	
Distribution Capacity Charge Receipts	(233,612)		(238,911)	
Power Factor Receipts	(2,513,565)		(2,513,565)	
Subtotal	24,110,497		26,313,770	
Indirect Cash Outflows (Inflows):				
Capital Contributions and Grant Receipts	(20,395,802)		(20,448,811)	
Debt Service	82,394,099		88,266,432	
Administration and General	19,491,473		20,538,264	
Taxes	14,111,315		15,942,135	
Cost of Capital	38,845,709		41,918,381	
Total Distribution-Wires and Related Equipment	**158,557,291**	**$16.81**	**172,530,172**	**$18.25**
Distribution-Transformers				
Direct Cash Outflows (Inflows):				
Distribution O&M-Transformers	2,605,751		2,755,065	
Credits for Customer-Owned Transformers	392,676		408,574	
Subtotal	2,998,427		3,163,639	
Indirect Cash Outflows (Inflows):				
Capital Contributions and Grant Receipts	(3,735,889)		(3,745,599)	

(Table 2.2 continued, page 4)

Functions	2017		2018	
	Dollars	$/MWh	Dollars	$/MWh
Debt Service	14,605,109		15,647,871	
Administration and General	1,878,859		1,979,763	
Taxes	2,208,731		2,511,387	
Cost of Capital	7,169,921		7,737,058	
Total Distribution-Transformers	**25,125,158**	**$2.66**	**27,294,119**	**$2.89**
Distribution-Meters				
Direct Cash Outflows (Inflows):				
Distribution O&M-Meters	3,713,731		3,926,534	
Indirect Cash Outflows (Inflows):				
Debt Service	4,876,414		5,222,561	
Administration and General	2,755,275		2,903,247	
Taxes	1,440,607		1,504,452	
Cost of Capital	2,082,348		2,247,061	
Total Distribution-Meters	**14,868,375**	**$1.58**	**15,803,855**	**$1.67**
Distribution-Streetlights/Floodlights				
Direct Cash Outflows (Inflows):				
Distribution O&M-Lights	2,612,707		2,762,420	
Indirect Cash Outflows (Inflows):				
Capital Contributions and Grant Receipts	(1,331,010)		(1,334,469)	
Debt Service	5,432,452		5,819,262	
Administration and General	1,434,022		1,511,036	
Taxes	1,067,520		1,185,498	
Cost of Capital	2,504,309		2,702,398	
Total Distribution-Streetlights/Floodlights	**11,719,999**	**$1.24**	**12,646,145**	**$1.34**
SUBTOTAL DISTRIBUTION	**255,528,617**	**$27.09**	**276,420,995**	**$29.23**
TOTAL DISTRIBUTION + IN SERVICE AREA TRANSMISSION	**272,260,222**	**$28.86**	**294,376,544**	**$31.13**
Customer Accounts and Services				
Direct Cash Outflows (Inflows):				
Customer Accounting and Advisory O&M	41,089,705		43,454,612	
Late Payment Fees	(3,759,031)		(3,796,621)	
Account Change Fees	(1,568,631)		(1,584,317)	
Miscellaneous Rental Receipts	(160,743)		(162,350)	
Reconnect Fees	(1,133,635)		(1,144,971)	

(Table 2.2 continued, page 5)

Functions	2017		2018	
	Dollars	$/MWh	Dollars	$/MWh
Subtotal	34,467,665		36,766,353	
Indirect Cash Outflows (Inflows):				
Debt Service	3,762,433		4,021,092	
Administration and General	24,898,094		26,235,247	
Taxes	7,889,857		8,217,062	
Cost of Capital	305,510		329,676	
Total Customer Accounts and Services	**71,323,559**	**$7.56**	**75,569,431**	**$7.99**
Utility Discount Program				
Direct Cash Outflows (Inflows):				
Utility Discount Program O&M	890,685		941,917	
Rate Discounts	16,872,102		17,884,428	
Bill Payment Assist. from Low-Income Acct.	313,884		321,308	
Account Change Fee Waiver	43,288		44,370	
Late Payment Fees	(127,618)		(128,894)	
Subtotal	17,992,341		19,063,129	
Indirect Cash Outflows (Inflows):				
Debt Service	80,304		85,825	
Administration and General	539,138		568,092	
Revenue Taxes	2,334,728		2,423,301	
Cost of Capital	6,521		7,036	
Total Utility Discount Program	**20,953,031**	**$2.22**	**22,147,384**	**$2.34**
TOTAL RETAIL SERVICES	**364,536,812**	**$38.65**	**392,093,358**	**$41.46**
SUBTOTAL RETAIL CUSTOMER REVENUE REQUIREMENT BEFORE CREDIT	**928,538,346**	**$98.44**	**979,775,244**	**$103.61**
CREDIT FOR NET WHOLESALE POWER SALES	**(60,000,002)**		**(60,000,002)**	
TOTAL REVENUE REQUIREMENT	**868,538,344**	**$92.08**	**919,775,242**	**$97.27**

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) Slice and 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, and 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: Direct outflows of in service area transmission include transmission load dispatching, switching stations, inspecting and testing lines and engineering. City Light 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 load dispatching and substations, overhead and underground lines, public lighting, meters, poles, vaults, ducts, and transformers.

Direct distribution outflows are allocated among five sub-functions: stations, wires and related equipment (wires), transformers, meters and streetlights/floodlights (lights). 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 five distribution sub-functions.

Table 2.3: Direct Distribution Expenses Allocation Percentages 2017-2018

Distribution Sub-Function	2017	2018
Stations	24.8%	24.8%
Wires	61.8%	61.8%
Transformers	3.9%	3.9%
Meters	5.6%	5.6%
Lights	3.9%	3.9%

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

- Wires include an offset for inflows from property rental and damages, construction charges, pole attachment, 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 was reduced with the difference allocated across the remaining distribution sub-functions.

Customer Accounts and Services: Direct outflows in this category cover meter reading, 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 accounts and services (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. 2017 and 2018 forecasted contributions relate primarily to distribution projects though a minor amount is attributable to transmission projects. In order to smooth out the variation in annual contributions, a three year average of historical contributions was allocated to functionalized categories, which include in-service area transmission and all distribution categories except meters. Depreciation, as a measure of the depleted resources that will require future contributions, was used to allocate the three-year average.

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 purchases 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	**$759,249,296**	**28.9%**	**$22,223,372**	**18.0%**
Hydroelectric Plant	*473,196,613*		*15,021,861*	
Share of General Plant	*30,041,502*		*3,562,610*	
Unamortized Hydro Project Relicensing	*108,290,521*		*3,291,496*	
Unamortized High Ross & Skagit Endowment	*147,720,660*		*347,404*	
Conservation	**228,572,036**	**8.7%**	**19,243,349**	**15.6%**
Unamortized Conservation	*228,107,459*		*19,117,356*	
Share of General Plant	*464,577*		*125,993*	
Transmission				
Long-Distance Transmission	**63,360,990**	**2.4%**	**2,940,229**	**2.4%**
Transmission Plant	*59,247,341*		*2,280,679*	
Share of General Plant	*3,517,934*		*659,550*	
Unamortized Puget Stillwater Substation	*595,715*		*0*	
In Service-Area Transmission	**97,319,810**	**3.7%**	**3,348,423**	**2.7%**
Transmission Plant	91,865,128		2,966,995	
Share of General Plant	5,454,682		381,428	
Distribution				
Stations	**86,009,934**	**3.3%**	**6,971,133**	**5.7%**
Distribution Plant	*81,748,103*		*4,327,998*	
Share of General Plant	*4,261,831*		*2,643,135*	
Wires and Related Equipment	**1,059,909,559**	**40.4%**	**50,823,781**	**41.2%**
Distribution Plant	*1,007,390,564*		*46,805,163*	
Share of General Plant	*52,518,995*		*4,018,618*	
Transformers	**195,632,109**	**7.5%**	**9,020,617**	**7.3%**
Distribution Plant	*185,938,450*		*8,573,280*	
Share of General Plant	*9,693,659*		*447,337*	
Meters	**56,817,106**	**2.2%**	**2,999,082**	**2.4%**
Distribution Plant	*54,001,793*		*2,367,931*	
Share of General Plant	*2,815,313*		*631,151*	
Streetlights/Floodlights	**68,330,357**	**2.6%**	**3,348,611**	**2.7%**
Distribution Plant	*64,944,557*		*3,054,458*	
Share of General Plant	*3,385,800*		*294,153*	
Customer Accounts and Services	**8,335,877**	**0.3%**	**2,260,685**	**1.8%**
Share of General Plant	*8,335,877*		*2,260,685*	
Utility Discount Program	**177,918**	**0.0%**	**48,251**	**0.0%**
Share of General Plant	*177,918*		*48,251*	
Total	**$2,623,714,992**	**100.0%**	**$123,227,533**	**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 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 and the Concrete School District 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 taken into account. 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 network areas (downtown, First Hill and University District), not just the area assigned Downtown Network rates. For cost allocation purposes, approximately 85% of the network outflows shown below are allocated to the Downtown Network; this allocation is based on historical consumption percentages. The other 15% 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 computed for the non-network and network categories by multiplying the sum of all net outflows, excluding tax payments, in each category by the effective tax rate.

The 2017 and 2018 non-network/network breakdown of projected revenue requirements for wires and related equipment and transformers is shown in **Table 2.5**.

Table 2.5: 2017 and 2018 Non-network/Network Cash Outflows (net)

	2017		2018	
Wires and Related Equipment	**Non-network**	**Network**	**Non-network**	**Network**
Wires and Related Equipment	$37,475,858	$3,600,844	$39,623,286	$3,807,179
Property Rental Inflows	(2,398,342)	(230,443)	(2,422,324)	(232,748)
Inflows from Damage	(1,529,489)	(146,960)	(1,544,784)	(148,430)
Other O&M Inflows	(6,866,047)	(659,720)	(6,937,445)	(666,580)
Construction (Installation) Inflows	(4,926)	(473)	(4,975)	(478)
Pole Attachment Inflows	(2,382,628)	0	(2,406,454)	0
Distribution Capacity Inflows	(233,612)	0	(238,911)	0
Power Factor Inflows	(2,293,222)	(220,343)	(2,293,222)	(220,343)
Subtotal	**$21,767,592**	**$2,342,905**	**$23,775,170**	**$2,538,601**
Contributions and Grant Inflows	(13,460,416)	(6,935,386)	(13,495,400)	(6,953,411)
Debt Service Payments	54,376,820	28,017,278	58,252,327	30,014,106
Administrative and General Outflows	17,556,131	1,935,342	18,498,984	2,039,280
Tax Payments	10,722,451	3,388,864	12,099,637	3,842,498
Cost of Capital and Risk Management	25,636,619	13,209,090	27,664,460	14,253,921
Total Wires and Related Equipment	**$116,599,198**	**$41,958,093**	**$126,795,178**	**$45,734,994**

	2017		2018	
Transformers	**Non-network**	**Network**	**Non-network**	**Network**
Distribution O&M-Transformers	$246,126	$2,359,625	$260,230	$2,494,836
Customer-Owned Transformer Credits	392,676	0	408,574	0
Subtotal	**$638,802**	**$2,359,625**	**$668,804**	**$2,494,836**
Contributions and Grant Inflows	(2,243,517)	(1,492,373)	(2,249,348)	(1,496,251)
Debt Service Payments	8,770,818	5,834,291	9,397,029	6,250,842
Administrative and General Outflows	141,483	1,737,376	149,081	1,830,682
Tax Payments	1,025,021	1,183,710	1,173,589	1,337,798
Cost of Capital and Risk Management	4,305,759	2,864,162	4,646,342	3,090,716
Total Transformers	**$12,638,366**	**$12,486,792**	**$13,785,497**	**$13,508,622**

3. Cost of Service and 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.

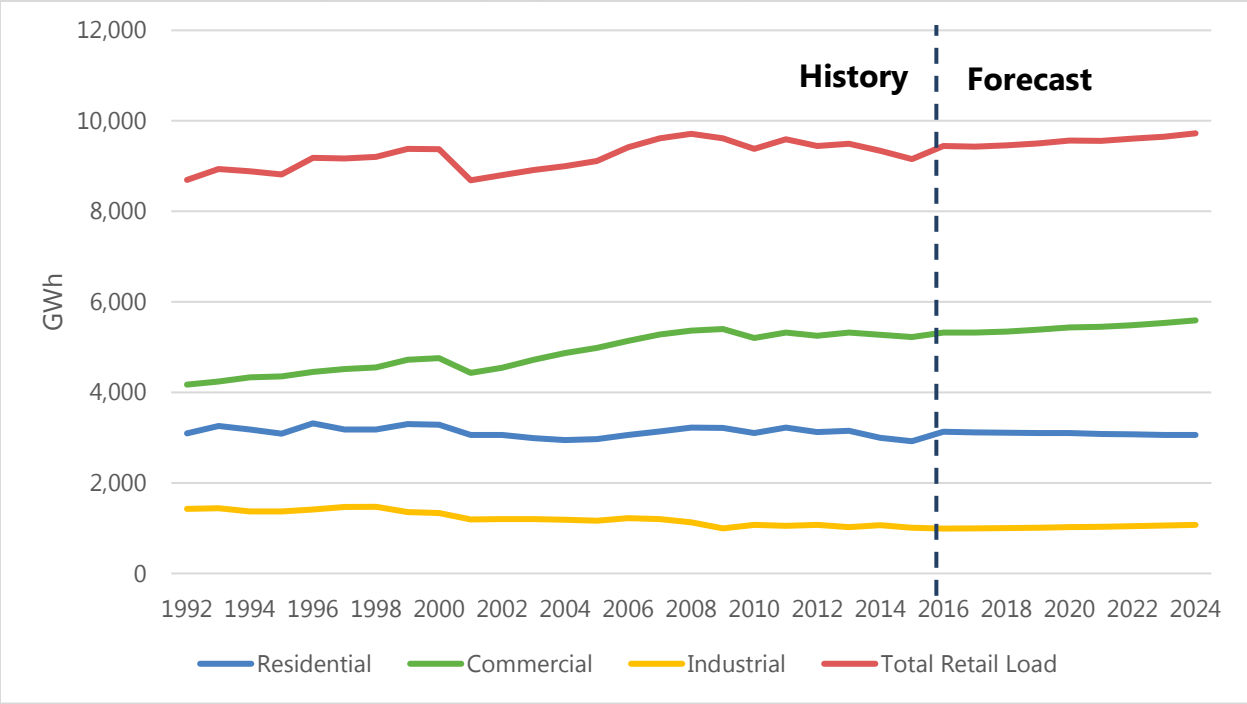
3.2 Load Overview

The retail load (or retail sales) 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

The retail load forecast is based on forecasts of selected economic and demographic variables for the service territory and includes assumptions about conservation programs and customer price elasticity of demand. **Figure 3.1** shows the 2015 corporate retail load forecast, which was produced in the spring of 2015. 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



Billing determinants are detailed forecasts of consumption which yield an estimate of revenue given a set of retail rates. To develop billing determinants, the commercial and industrial load forecasts are allocated to Small, Medium, Large and High Demand customer classes. Load is further divided into network and non-network classes. **Tables 3.1** and **3.2** show forecasted consumption by customer class for 2017 and 2018, respectively.

Table 3.1: Energy Consumption by Customer Class in 2017

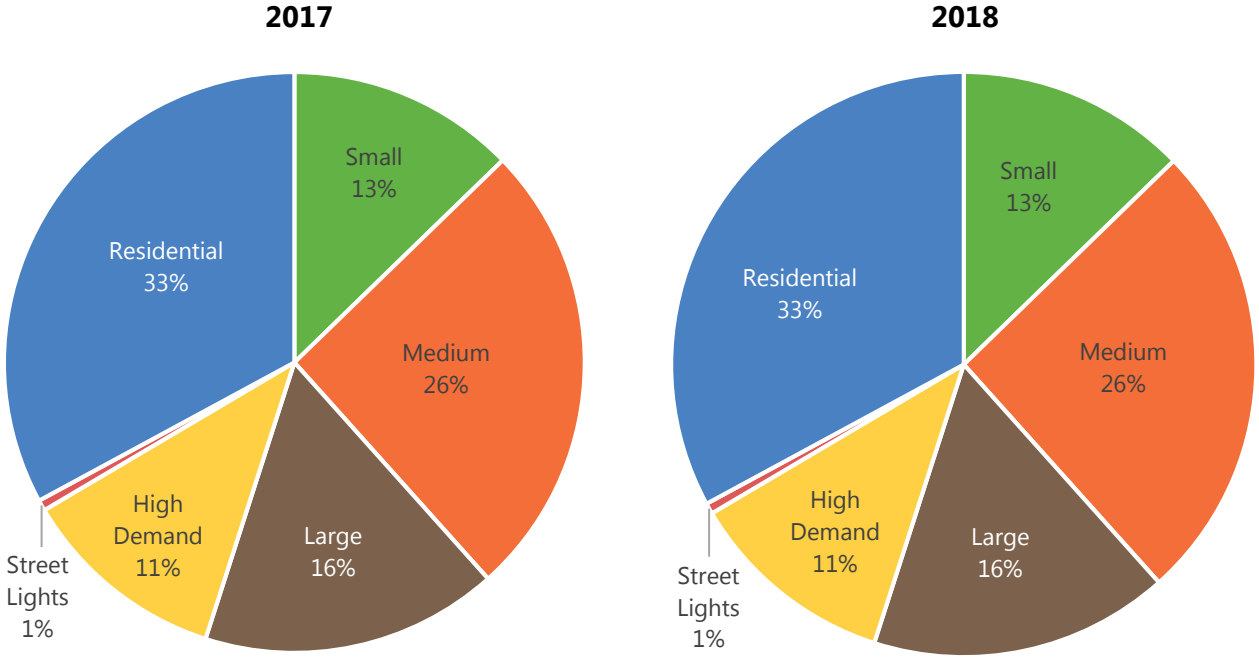
2017	Total	Residential	Small	Medium	Large	High Demand	Lights
Service Territory	9,432,200	3,117,600	1,198,799	2,411,755	1,559,344	1,085,520	59,183
Non-network	8,068,223	3,030,311	1,060,358	1,904,426	928,426	1,085,520	59,183
Network	1,363,977	87,289	138,441	507,328	630,918		

Table 3.2: Energy Consumption by Customer Class in 2018

2018	Total	Residential	Small	Medium	Large	High Demand	Lights
Service Territory	9,456,100	3,110,500	1,204,720	2,424,023	1,567,566	1,092,785	56,507
Non-network	8,085,731	3,023,410	1,065,595	1,914,114	933,321	1,092,785	56,507
Network	1,370,369	87,090	139,125	509,909	634,245		

Figure 3.2 presents the consumption mix by customer class. Residential electricity consumption constitutes 33% of total retail load and non-residential is 67%. There are no major differences in the consumption mix between the two years.

Figure 3.2: Percent of Retail Sales by Customer Class, 2017-2018



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 2017 and 2018 for 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 pm to 6 am 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 Retail Sales by Customer Class, 2017-2018

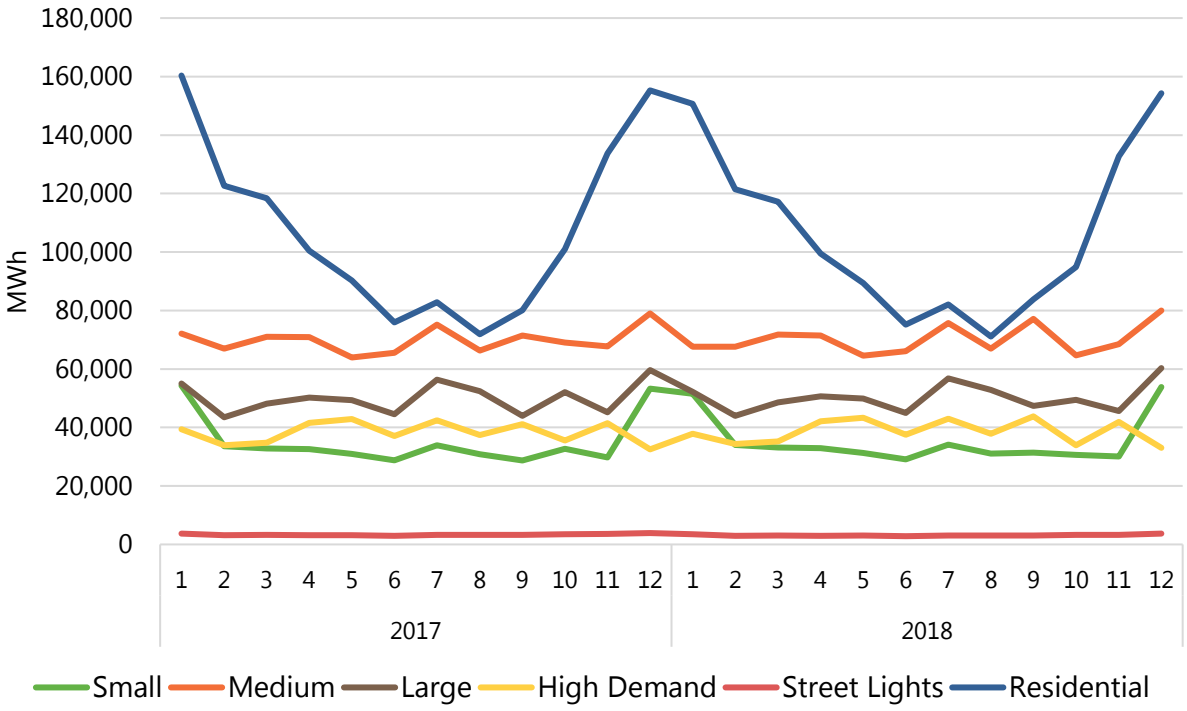
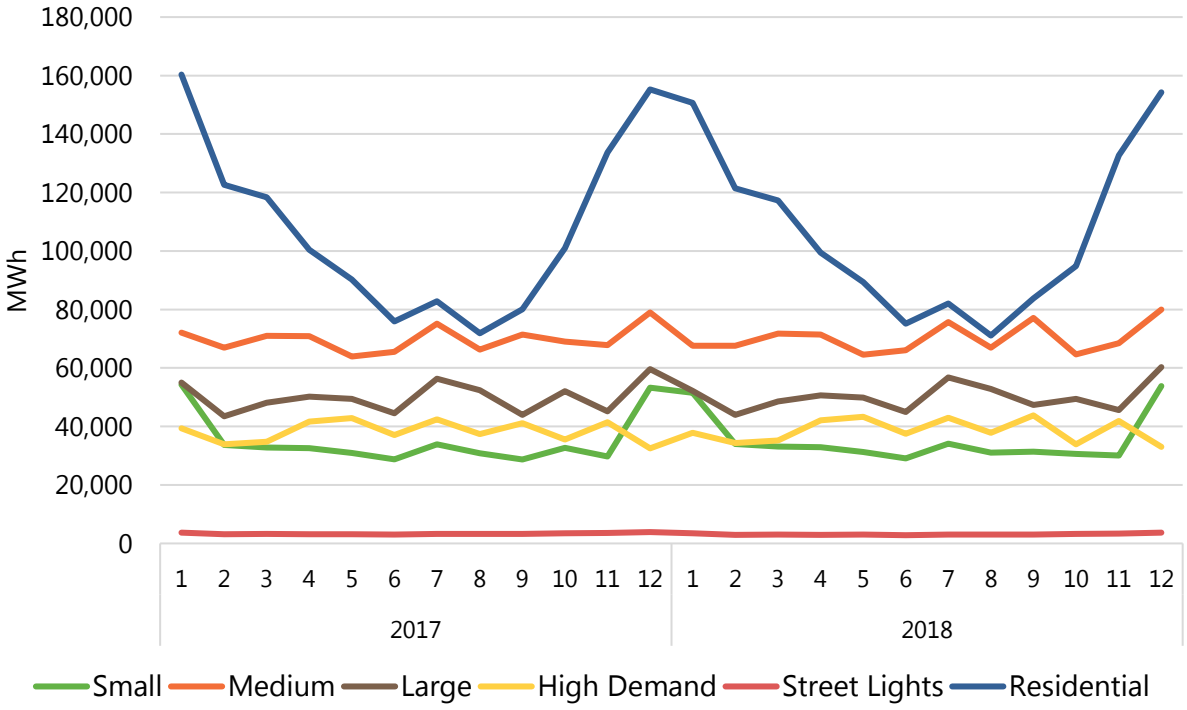


Figure 3.4: Off-Peak Retail Sales by Customer Class, 2017-2018



3.2.2 Peak Load Data

Coincident peak load is used to help allocate certain distribution costs. Peak load is defined as the maximum of either peak or off-peak monthly average consumption. For customer classes, coincident peak load is defined as the average monthly load during the month of the total system peak. **Table 3.3** summarizes average and coincident peak load for 2017 and 2018 by customer class. For 2017 and 2018 City Light's system peak is forecast to occur in the December 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	2017	921.0	345.9	121.0	217.4	106.0	123.9	6.8
	2018	923.0	345.1	121.6	218.5	106.5	124.7	6.5
Load at Coincident Peak*, MW	2017	1,196.4	513.3	180.2	264.1	125.6	135.7	11.3
	2018	1,197.5	513.9	180.4	264.8	125.7	136.2	10.8
Network								
		Total	**Residential**	**Small**	**Medium**	**Large**		
Average Annual Load, MW	2017	155.7	10.0	15.8	57.9	72.0		
	2018	156.4	9.9	15.9	58.2	72.4		
Load at Coincident Peak*, MW	2017	192.4	14.8	23.5	70.4	85.3		
	2018	192.6	14.8	23.6	70.5	85.4		

*Coincident peak is forecast to occur during December 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 which 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)[3]

Energy Flow Point	Residential	Small and Streetlights	Medium	Large and High Demand
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 which are used as a basis to compute the cost of energy.

Table 3.5: 2017 Energy Consumption plus Losses by Customer Class

2017	Total	Residential	Small	Medium	Large	High Demand	Lights
Service Territory	9,901,586	3,259,446	1,252,298	2,539,578	1,641,692	1,146,478	62,094
Non-network	8,467,253	3,168,186	1,107,678	2,005,361	977,455	1,146,478	62,094
Network	1,434,333	91,260	144,620	534,217	664,237	0	0

Table 3.6: 2018 Energy Consumption plus Losses by Customer Class

2018	Total	Residential	Small	Medium	Large	High Demand	Lights
Service Territory	9,927,370	3,251,817	1,258,602	2,552,704	1,650,627	1,154,366	59,253
Non-network	8,486,146	3,160,770	1,113,255	2,015,726	982,775	1,154,366	59,253
Network	1,441,224	91,047	145,348	536,978	667,852	0	0

3.2.4 Meter Counts

Tables 3.7 and **3.8** show the projected average number of meters by customer class for 2017 and 2018, respectively. Since new customers (meters) are continuously getting 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.

[3] 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.

The meter data is based on 2015 billing data, and since there is little change projected in system load, the counts remain relatively consistent for both years.

Table 3.7: 2017 Meter Count

2017	Total	Residential	Small	Medium	Large	High Demand
Service Territory	447,761	399,976	44,416	3,202	155	12
Non-network	423,548	379,557	41,228	2,656	95	12
Network	24,213	20,419	3,188	546	60	

Table 3.8: 2018 Meter Count

2018	Total	Residential	Small	Medium	Large	High Demand
Service Territory	448,014	399,991	44,635	3,220	156	12
Non-network	423,781	379,572	41,431	2,671	95	12
Network	24,233	20,419	3,204	549	61	

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 the month; P is the peak period; OP is the off-peak period; Q is energy consumption; L is energy losses; P is the wholesale market price; EA is an externality adder.

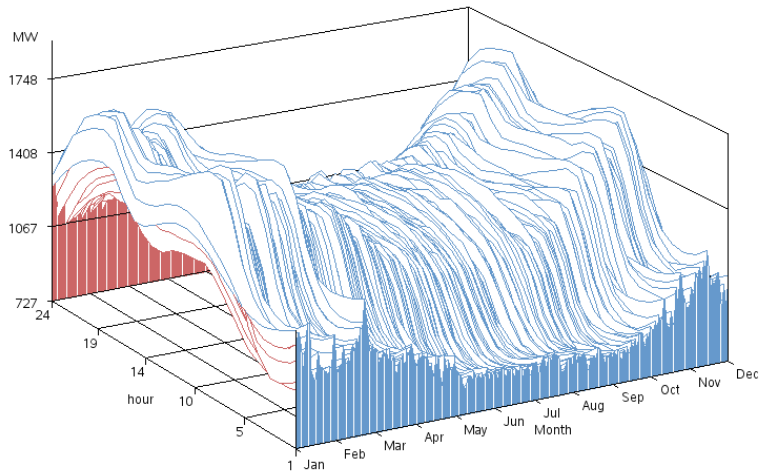
3.3.1 Wholesale Market Electricity Prices

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 and then decrease in the spring during the hydro runoff season when there is an abundance of generation. Prices 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 2006-2015. Market prices were rising between 2005 and mid-2008, falling rapidly after that following the financial crisis in the fall of 2008, falling a little further in 2009-2012 due to lower natural gas prices, then gradually climbing upward from mid-2012 to the end of 2013. More recently in 2014-2015 Mid-C prices have declined again due to persistently low natural gas prices.

Figure 3.6: Average Monthly Mid-C Electricity Prices, 2006-2015

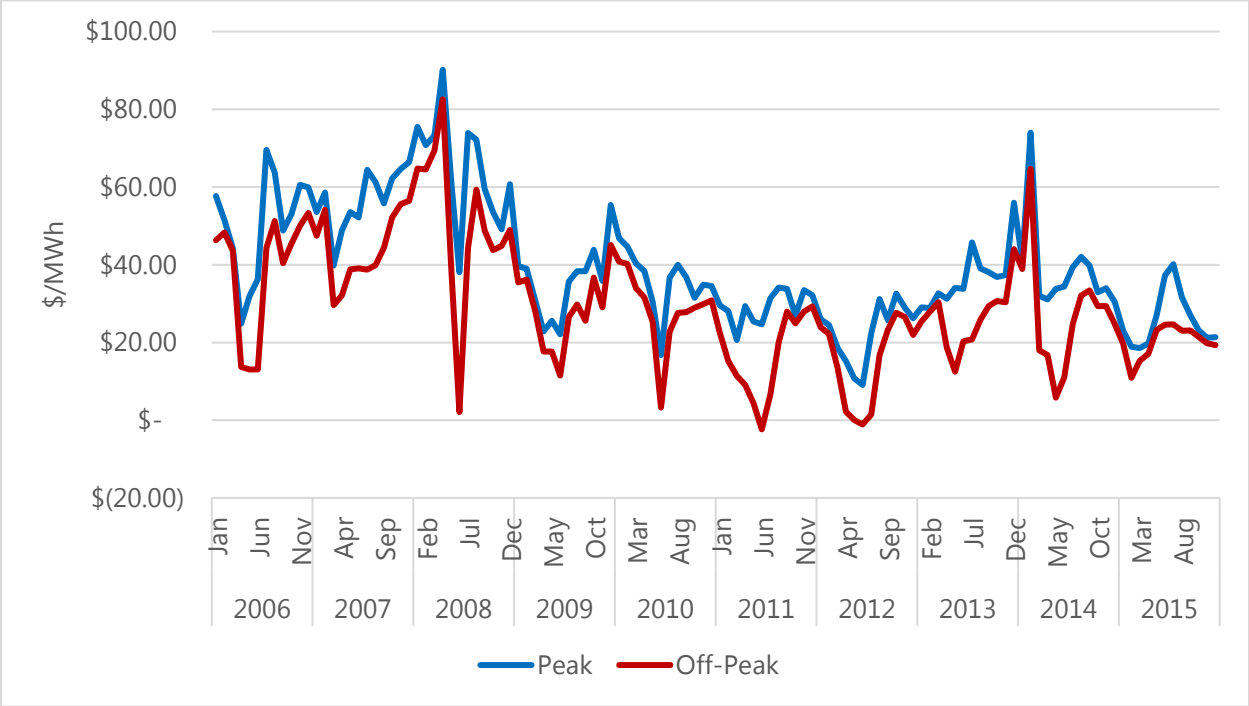
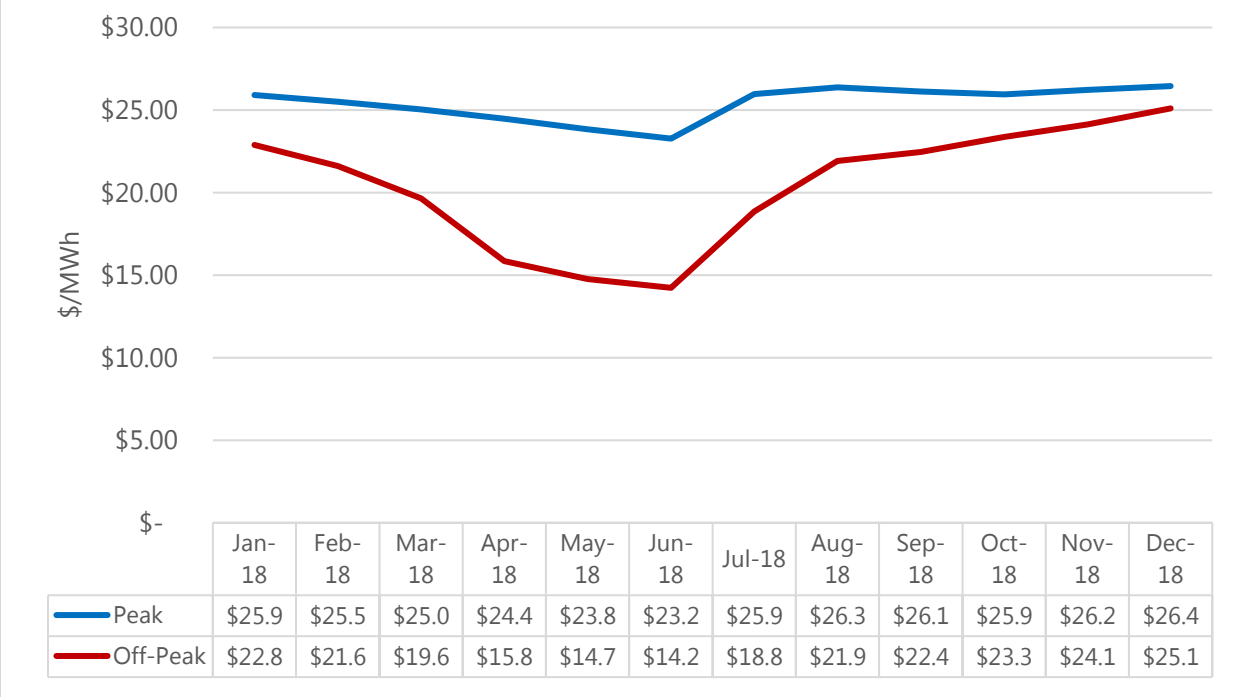
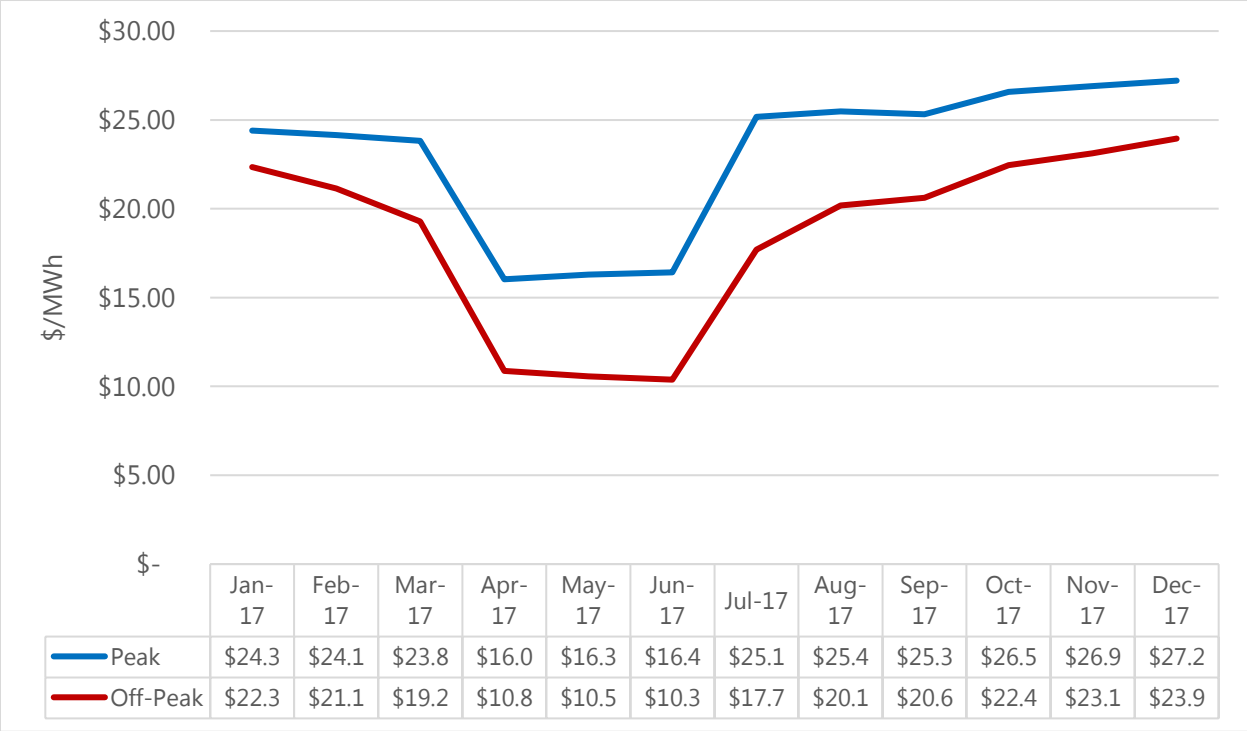


Figure 3.7 presents the forecast of monthly Mid-C electricity prices for 2017 and 2018 which is based on forward wholesale market prices as of March 3, 2016. Peak prices are expected to remain around the same level in 2017 and 2018, with the exception of spring when peak and off-peak prices are expected to be higher in 2018.

Figure 3.7: Monthly Mid-C Electricity Prices, 2017-2018



	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18
Peak	$25.9	$25.5	$25.0	$24.4	$23.8	$23.2	$25.9	$26.3	$26.1	$25.9	$26.2	$26.4
Off-Peak	$22.8	$21.6	$19.6	$15.8	$14.7	$14.2	$18.8	$21.9	$22.4	$23.3	$24.1	$25.1



	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17
Peak	$24.3	$24.1	$23.8	$16.0	$16.3	$16.4	$25.1	$25.4	$25.3	$26.5	$26.9	$27.2
Off-Peak	$22.3	$21.1	$19.2	$10.8	$10.5	$10.3	$17.7	$20.1	$20.6	$22.4	$23.1	$23.9

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 estimated based on an EPA estimate for the Northwest Region.

The price of CO_2 emissions for the period 2012–2017 is based on the City Light forecast of the cost of greenhouse gas offsets for those years. Starting in 2018, City Light expects environmental regulations to come into effect. These prices are assumed to be applied to all CO_2 emissions.

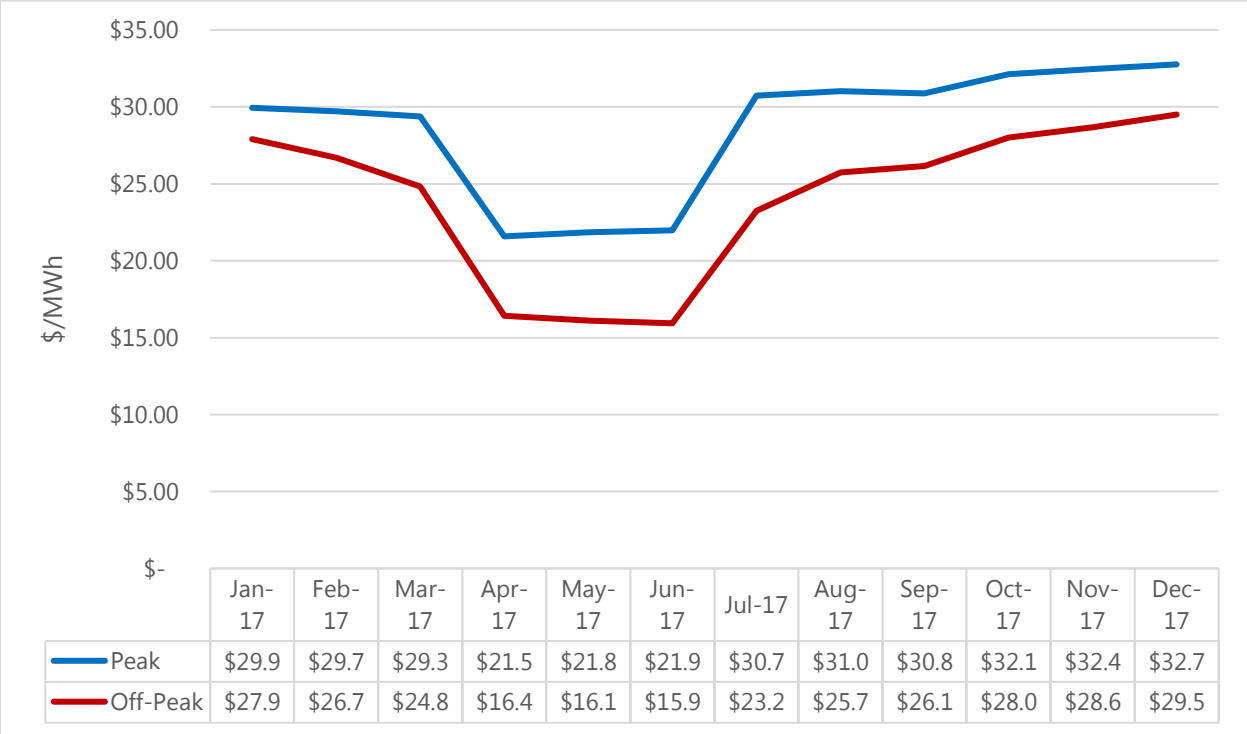
The environmental externality adder is calculated by multiplying the amount of CO_2 emitted per MWh by the price of CO_2 emissions. **Table 3.9** shows emission factors, price of CO_2 emissions and resulting adders for 2017 and 2018.

Table 3.9: Environmental Externality Adders, 2017-2018

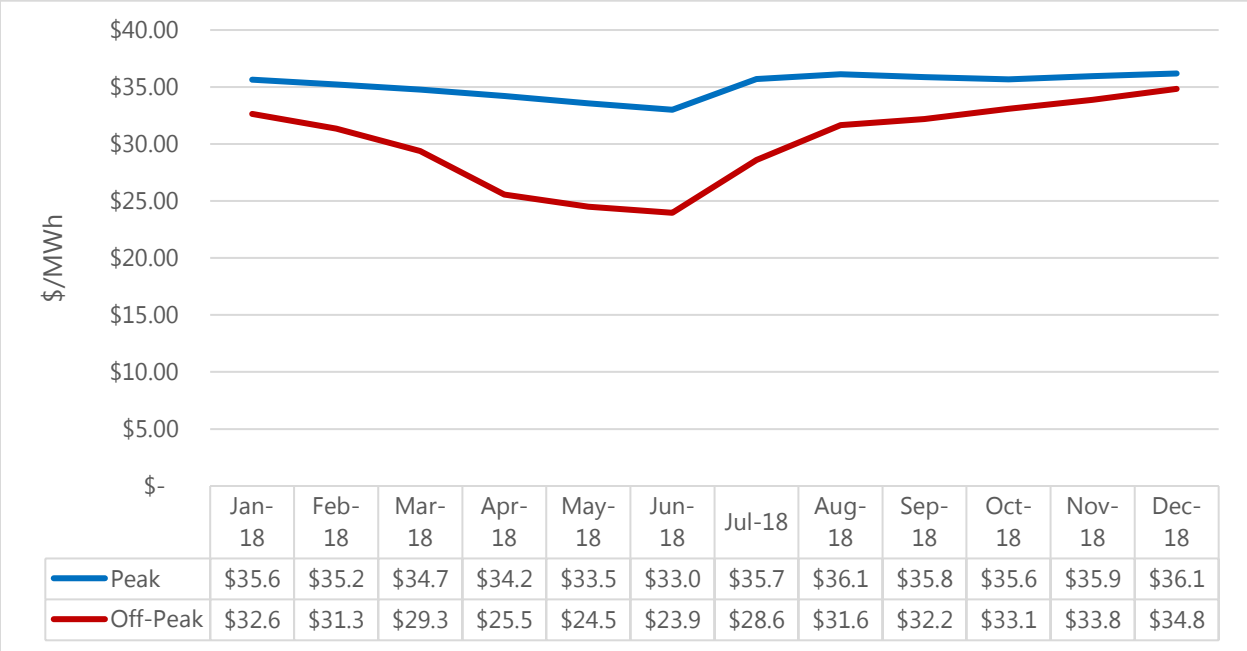
Year	CO_2 Emission Factor (metric tons/MWh)	Price of CO_2 Emissions ($/metric ton, in 2015$)	Environmental Externality Adder ($/MWh, in 2015$)
2017	0.678	$8.00	**$5.42**
2018	0.658	$14.10	**$9.28**

Figure 3.8 presents the forecast of Mid-C monthly electricity prices plus externality costs for 2017 and 2018.

Figure 3.8: Monthly Mid-C Electricity Prices plus Externality Costs, 2017-2018



	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17
Peak	$29.9	$29.7	$29.3	$21.5	$21.8	$21.9	$30.7	$31.0	$30.8	$32.1	$32.4	$32.7
Off-Peak	$27.9	$26.7	$24.8	$16.4	$16.1	$15.9	$23.2	$25.7	$26.1	$28.0	$28.6	$29.5



	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18
Peak	$35.6	$35.2	$34.7	$34.2	$33.5	$33.0	$35.7	$36.1	$35.8	$35.6	$35.9	$36.1
Off-Peak	$32.6	$31.3	$29.3	$25.5	$24.5	$23.9	$28.6	$31.6	$32.2	$33.1	$33.8	$34.8

3.3.3 Energy Consumption plus Losses Costs

Tables 3.10 and **3.11** present the total costs of energy consumption plus losses by customer class for 2017 and 2018. 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 the results for each year. Note that the costs increase in 2018 for all customer classes, reflecting the projected increase in wholesale market prices and increased externality costs due to environmental regulations coming into effect.

Table 3.10: Costs of Energy Consumption plus Losses in 2017

2017	Total	Residential	Small	Medium	Large	High Demand	Lights
Service Territory	$269,103,344	$89,097,629	$34,337,604	$69,108,403	$44,386,205	$30,555,502	$1,618,001
Non-network	$230,147,020	$86,603,014	$30,372,181	$54,570,996	$26,427,327	$30,555,502	$1,618,001
Network	$38,956,324	$2,494,615	$3,965,423	$14,537,408	$17,958,878		

Table 3.11: Costs of Energy Consumption plus Losses in 2018

2018	Total	Residential	Small	Medium	Large	High Demand	Lights
Service Territory	$331,134,827	$108,547,627	$42,259,550	$85,436,777	$54,940,327	$38,053,968	$1,896,577
Non-network	$283,014,045	$105,508,438	$37,379,274	$67,464,588	$32,711,199	$38,053,968	$1,896,577
Network	$48,120,782	$3,039,189	$4,880,276	$17,972,189	$22,229,128		

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 1,077 MW for 2017 and 1,080 MW for 2018. Transmission capacity required, therefore, is 1,830 MW and 1,835 MW for 2017 and 2018, respectively.

The price for BPA transmission services is $1,817/MW per month in 2017 and $1,931/MW per month in 2018. The annual long distance transmission costs, therefore, are $39,907,832 for 2017 and $42,513,947 for 2018, 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.[4] The results were summed over all classes.

[4] 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.

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 2017 and 2018.

Table 3.12: Long Distance Transmission Costs in 2017

2017	Total	Residential	Small	Medium	Large	High Demand	Lights
Service Territory	$39,907,832	$13,190,630	$5,072,144	$10,204,183	$6,597,617	$4,592,855	$250,403
Non-network	$34,136,818	$12,821,310	$4,486,396	$8,057,666	$3,928,189	$4,592,855	$250,403
Network	$5,771,014	$369,320	$585,748	$2,146,517	$2,669,429		

Table 3.13: Long Distance Transmission Costs in 2018

2018	Total	Residential	Small	Medium	Large	High Demand	Lights
Service Territory	$42,513,947	$13,984,585	$5,416,334	$10,898,235	$7,047,663	$4,913,081	$254,050
Non-network	$36,352,866	$13,593,035	$4,790,837	$8,605,720	$4,196,144	$4,913,081	$254,050
Network	$6,161,081	$391,550	$625,497	$2,292,516	$2,851,519		

City Light earns 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 2017 and 2018. These costs are used to derive energy allocation factors by customer class summarized in Section 3.6.

Table 3.14: Total Energy Costs in 2017

2017	Total	Residential	Small	Medium	Large	High Demand	Lights
Service Territory	$309,011,176	$102,288,259	$39,409,748	$79,312,587	$50,983,822	$35,148,357	$1,868,403
Non-network	$264,283,838	$99,424,324	$34,858,577	$62,628,662	$30,355,516	$35,148,357	$1,868,403
Network	$44,727,338	$2,863,935	$4,551,171	$16,683,925	$20,628,306		

Table 3.15: Total Energy Costs in 2018

2018	Total	Residential	Small	Medium	Large	High Demand	Lights
Service Territory	$373,648,774	$122,532,212	$47,675,884	$96,335,012	$61,987,990	$42,967,049	$2,150,627
Non-network	$319,366,911	$119,101,473	$42,170,111	$76,070,308	$36,907,343	$42,967,049	$2,150,627
Network	$54,281,863	$3,430,739	$5,505,773	$20,264,704	$25,080,647		

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 2,892 miles of line estimated within the service territory. Appendix A indicates that the expected service life for this type of equipment is 42 years with a corresponding annualization factor of 0.042192. 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	2014 $Millions/Mile	Total 2014$Millions
115 kV			
Overhead (OH)	97.2	$3.2	$308.6
Underground (UG)	21.1	10.6	223.2
Subtotal	118.3	4.5	531.8
230 kV			
Overhead (OH)	92.9	$3.7	$343.9
Underground (UG)	19.2	12.7	243.1
Subtotal	112.0	5.2	587.0
Total	**230.4**	**$4.9**	**$1,118.9**
Annualization factor			0.042192
In Service Area Capacity (MW)			2,892
Loss Factor			2.7%
Annual Capital Cost $2014 /per MW			**$16,776**

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 2012 through 2014. 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 2012-2014

FERC Code	FERC #	2012	2013	2014
OS&E-INSIDE SEATTLE	56016	$17,062	$6,343	$78
O-STATION EXP, INSIDE SEATTLE	56216	27,008	29,047	28,854
OP OV LINE EXP-INSIDE SEATTLE	56316	0	0	0
OP UN LINE EXP-INSIDE SEATTLE	56416	4,064	4,126	15,150
OP MISC L EXP-INSIDE SEATTLE	56616	0	102,535	27,864
MS&E-INSIDE SEATTLE	56816	36,614	11,659	13
MAINT TRANS ST-INSIDE SEATTLE	56916	82,792	21,024	2,945
MAINT RELAY SE-INSIDE SEATTLE	57016	127,045	26,246	25,547
MAINT STAT EQ-INSIDE SEATTLE	57026	468,686	1,008,032	722,107
ROADS & TRAILS-INSIDE SEATTLE	57116	133,013	39,014	23,117
TOWERS & POLES-INSIDE SEATTLE	57126	0	8,349	112,243
M O/H TRANS CO-INSIDE SEATTLE	57136	(9,102)	0	0
CLR TREE&BRSH-INSIDE SEATTLE	57146	24,780	349,848	221,468
MAINT O/H ENG-INSIDE SEATTLE	57156	380	0	0
U/G NON ELEC EQ-INSIDE SEATTLE	57216	1,385	3,497	8,164
U/G ELEC EQ-INSIDE SEATTLE	57226	0	1,847	0
U/G ELEC ACCESS-INSIDE SEATTLE	57236	0	946	4,930
U/G MAINT ENG-INSIDE SEATTLE	57246	0	2,634	0
MISC TRANS PLA-INSIDE SEATTLE	57316	65,102	55,230	148
SUBTOTAL (excl 56016 - a supervisory cost)		961,765	1,664,036	1,192,551
Subtotal in $2014		**$992,307**	**$1,696,202**	**$1,192,551**
$Three Year Average				1,293,686
In Service Area Capacity (MW)				2,892
Annual O&M, $2014/MW				**$447**

Total In Service Area Transmission Costs by Customer Class

Tables 3.18 and **3.19** present total in service area transmission costs for 2017 and 2018, 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: 2017 In Service Area Transmission Costs

Capital Costs $2014/MW			$16,776				
O&M Costs $2014/MW			$447				
In Service Area Transmission Capacity MW			2,892				
2017 Coincident Peak Load (MW)							
	Total	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Non-network	1,196.4	513.3	177.8	258.7	123.3	117.3	6.0
Network	192.4	14.3	23.5	69.1	85.3		
Service Territory	1,388.8						
2017 In Service Area Transmission Costs					**$2017 inflation adjustment =**		**1.05801**
	Total	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Non-network	$45,400,210	$19,478,652	$6,746,441	$9,817,851	$4,678,930	$4,450,658	$227,678
Network	$7,299,453	$544,502	$892,789	$2,623,769	$3,238,392		
Service Territory	$52,699,662	$20,023,154	$7,639,230	$12,441,621	$7,917,322	$4,450,658	$227,678

Table 3.19: 2018 In Service Area Transmission Costs

Capital Costs $2014/MW			$16,776				
O&M Costs $2014/MW			$447				
In Service Area Transmission Capacity MW			2,892				
2018 Coincident Peak Load (MW)							
	Total	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Non-network	1,197.5	513.9	178.0	259.0	123.4	117.4	5.8
Network	192.6	14.4	23.6	69.2	85.4		
Service Territory	1,390.1						
2018 In Service Area Transmission Costs					**$2018 inflation adjustment =**		**1.08400**
	Total	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Non-network	$46,513,353	$19,960,518	$6,913,336	$10,060,727	$4,794,678	$4,560,759	$223,336
Network	$7,480,888	$558,036	$914,980	$2,688,986	$3,318,886		
Service Territory	$53,994,242	$20,518,554	$7,828,316	$12,749,713	$8,113,564	$4,560,759	$223,336

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 new 180 MW substation in the Denny Triangle area. This substation will support both 26 kV non-network feeders and 13 kV network feeders. Engineering estimates and costs developed for this project are the source of the initial capital cost estimates

for 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, $2014	**$64,419,561**	**$57,534,801**
Capacity (MW)	180	180
Annualization Factor	0.04384	0.04384
Loss Factor	1.56%	1.56%
Annual Capital Costs $2014/ MW	**$15,940**	**$14,236**

Annual substation capital costs per MW are 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 #	2012	2013	2014
1	Load Dispatching	58101	2,841,064	2,786,185	2,808,008
2	Distribution Substation Equipment	58201	4,537,730	4,381,419	3,859,341
	Maintenance of Station Equipment	59201	1,620,017	2,407,389	1,535,176
	Age Adjustment Factor		0.673	0.673	0.673
3	Maintenance of Station Equipment, Adj.		1,090,272	1,620,173	1,033,174
4	Maintenance of Distribution Structures	59101	1,647,170	1,480,773	1,584,423
5	Maintenance of Station Relay	59205	3,012	19,575	14,939
	Total (1+2+3+4+5)		10,116,235	10,268,549	9,284,945
	Total in $2014		**$10,437,489**	**$10,467,039**	**$9,284,945**
	Three year average				$10,063,158
	Substation Capacity (MW)	2,458			
	Annual O&M, $2014/MW				**$4,094**

Total Substation Costs

Total substation costs for 2017 and 2018 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: 2017 Substation Costs

Network Capital Costs $2014/MW					$15,940		
Non-network Capital Costs $2014/MW					$14,236		
O&M Costs $2014/MW					$4,094		
Total Substation Capacity MW					2,458		
2017 Coincident Peak Load (MW)							
	Total	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Non-network	1,196.4	513.3	177.8	258.7	123.3	117.3	6.0
Network	192.4	14.3	23.5	69.1	85.3		
Service Territory	1,388.8						
2017 Substation Costs					$2017 inflation adjustment =		1.05801
	Total	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Non-network	$41,066,696	$17,619,387	$6,102,484	$8,880,724	$4,232,319	$4,025,836	$205,946
Network	$7,216,339	$538,302	$882,623	$2,593,894	$3,201,519		
Service Territory	$48,283,035	$18,157,689	$6,985,107	$11,474,618	$7,433,839	$4,025,836	$205,946

Table 3.23: 2018 Substation Costs

Network Capital Costs $2014/MW					$15,940		
Non-network Capital Costs $2014/MW					$14,236		
O&M Costs $2014/MW					$4,094		
Total Substation Capacity MW					2,458		
2018 Coincident Peak Load (MW)							
	Total	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Non-network	1,197.5	513.9	178.0	259.0	123.4	117.4	5.8
Network	192.6	14.4	23.6	69.2	85.4		
Service Territory	1,390.1						
2018 Substation Costs					$2018 inflation adjustment =		1.08400
	Total	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Non-network	$42,073,588	$18,055,258	$6,253,448	$9,100,416	$4,337,019	$4,125,428	$202,018
Network	$7,395,709	$551,682	$904,562	$2,658,368	$3,281,096		
Service Territory	$49,469,297	$18,606,941	$7,158,010	$11,758,785	$7,618,116	$4,125,428	$202,018

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 Chapter 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	$595	$222	$818	20,508	$16,767,189
Pipe brace anchor	$894	$377	$1,271	6,237	$7,925,746
Push brace	$1,186	$1,398	$2,584	21	$54,261
Circuit Breaker	$3,136	$643	$3,778	173	$653,668
Sectionalizers	$896	$566	$1,462	143	$209,050
Cutout w/ limiter	$896	$566	$1,462	2,762	$4,037,725
Cutout w/o limiter	$896	$152	$1,048	3,980	$4,169,074
0'-29' Concrete, Laminated, Wood poles	$1,186	$434	$1,620	3,905	$6,327,374
30'-40' Concrete, Laminated, Wood poles	$1,186	$787	$1,973	26,815	$52,911,072
0'-40' Fiber Glass, and Plastic poles	$2,372	$4,270	$6,642	1,118	$7,425,821
40'-50' Fiber Glass poles	$2,372	$4,875	$7,247	5	$36,234
61'-69 Fiber Glass poles	$2,372	$6,561	$8,933	1	$8,933
40'-45' Concrete, Laminated, Wood poles	$1,186	$1,035	$2,222	15,595	$34,645,822
45'-50' Concrete, Laminated, Wood poles	$1,186	$1,398	$2,584	35,726	$92,310,148
51'-55' Concrete, Laminated, Wood poles	$1,186	$1,794	$2,980	7,000	$20,863,244
56'-60' Concrete, Laminated, Wood poles	$1,483	$2,006	$3,488	3,142	$10,960,769
61'-69' Concrete, Laminated, Wood poles	$1,483	$2,166	$3,649	1,890	$6,896,591
71'-80' Concrete, Laminated, Wood poles	$1,483	$1,710	$3,192	730	$2,330,447
#4 bare copper wire/ft, 1 phase	$23	$2	$26	4,134,555	$106,291,848
#4 bare copper wire/ft, 3 phase	$51	$5	$56	1,543,835	$87,057,120
397 ACSR, 3 phase, 600 amp	$65	$6	$72	2,694,554	$193,008,975
954 ACSR, 3 phase, 1200 amp	$85	$14	$99	676,869	$67,088,314
954 ACSR, 34 kV	$85	$16	$101	20,625	$2,090,674
1/0 triplex; inc open 2-#2 & 1-#4	$7	$1	$9	5,369,304	$45,737,750
1/0 quadplex	$7	$3	$11	7,441	$79,395
600 amp horizontal LB switch	$6,352	$6,272	$12,624	914	$11,537,998
600 amp riser LB switch	$7,246	$9,788	$17,034	461	$7,852,752
1200 amp horizontal LB switch	$7,765	$11,074	$18,838	343	$6,461,532
1200 amp riser LB switch	$11,187	$16,635	$27,822	142	$3,950,777
Handholes, ave 233 & 444	$5,399	$4,746	$10,145	11,603	$117,717,186
Manholes, 712	$28,579	$29,273	$57,852	161	$9,314,150
Vaults, ave, 577, 612, 814 & 818	$36,134	$34,650	$70,784	9,471	$670,395,834
Pads, ave	$4,167	$3,134	$7,302	1,290	$9,418,981
single 1/0 27 kV UG inc duct, trench	$409	$345	$754	982,704	$740,945,004
three 1/0 27 kV UG inc duct, trench	$409	$349	$758	1,264,737	$958,907,992
1000 kCM UG inc duct, trench	$535	$478	$1,013	544,260	$551,099,143
2-1000kCM UG inc duct, trench	$556	$561	$1,117	149,479	$166,918,691

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
2-way 600 amp vista w/ local control	$31,642	$67,373	$99,015	51	$5,049,778
3-way 600 amp vista w/ local control	$32,351	$45,968	$78,319	12	$939,823
3-way 600 & 900 amp vista w/ provision for remote control	$41,506	$45,968	$87,474	5	$437,371
4-way 600 & 900 amp vista w/ local control	$40,896	$59,032	$99,929	15	$1,498,931
4-way 600 amp vista w/ provision for remote control	$50,052	$59,032	$109,085	12	$1,309,015
5-way 600 amp vista w/ local control	$37,539	$60,511	$98,050	4	$392,201
5-way 600 amp vista w/ provision for remote control	$46,695	$60,511	$107,206	9	$964,854
6-way 600 amp vista w/ local control	$45,047	$72,613	$117,660	1	$117,660
6-way 600 & 900 amp vista w/ provision for remote control	$56,034	$72,613	$128,647	26	$3,344,828
PMH 9 switch	$27,468	$35,414	$62,882	70	$4,401,733
PMH10 switch	$30,520	$36,178	$66,697	10	$666,972
PMH11 switch	$28,994	$35,796	$64,790	6	$388,737
PMH12 switch	$25,942	$37,632	$63,574	26	$1,652,911
600 amp metal clad switch gear bay	$7,630	$116,177	$123,806	62	$7,676,001
1200 amp metal clad switch gear bay	$15,260	$174,265	$189,525	6	$1,137,148
Terminators	$4,120	$3,793	$7,913	3,574	$28,280,511
1-3 Pos LB J-Box	$7,325	$690	$8,014	923	$7,397,350
3-3 Pos LB J-Box	$5,188	$1,806	$6,994	901	$6,301,671
1-4 Pos LB J-Box	$7,325	$864	$8,189	377	$3,087,317
3-4 Pos LB J-Box	$5,188	$2,330	$7,518	1,027	$7,721,196
1-5 Pos LB J-Box	$8,545	$2,269	$10,814	15	$162,215
3-5 Pos LB J-Box	$6,714	$6,543	$13,257	191	$2,532,163
Total in $2014					**$4,109,867,673**
Total Capacity MW					5,603
Annualization factor					0.0490466
Loss Factor					0.82%
Annual Capital Costs $2014/ MW					**$36,273**

Table 3.25: Network Wires and Related Equipment Capital Cost

	Per Unit Cost	# of Units	Total Cost
System Man Hole/Vaults	$282,354	1,394	$393,601,993
System Hand Holes	113,146	474	53,631,021
System Ducts	2,548	452,116	1,152,138,346
System Primary Feeder Cable	17,457	5,053	88,218,993
System Secondary Cables	10,324	1,865	19,251,823
Service Cables	10,324	498	5,141,781
Cable Limiters	102	43,179	4,401,364
Secondary Bus Bars	4,798	1,101	5,282,582
Total in $2014			**$1,721,667,905**
Total Capacity MW			660
Annualization factor			0.0490466
Loss Factor			0.82%
Annual Capital Costs $2014/ MW			**$129,000**

Wires and Related Equipment O&M Costs

Table 3.26 presents the annual O&M costs for non-network service for the years 2012 through 2014, 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 the proportion of total network load. In 2014, 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 2012 through 2014, 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 2014 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 we divide the three year average total non-network or network annual costs in $2014 by the non-network or network capacity.

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

FERC Code	FERC #	2012	2013	2014
Non-network Costs				
INSP TEST & PATROL OH DIST LIN	58352	$1,483,587	$718,063	$544,880
OH LINE ENGR EXP	58359	175,163	155,341	276,067
CLEAR TREES & TRIM BRUSH OH LI	59350	4,647,191	6,231,873	4,921,017
MAINT POLES CONDCTRS & SERVICE	59352	5,788,040	5,622,978	5,850,882
INSP & TEST UG DIST	58462	1,416,287	1,560,914	1,521,087
UG ENGR LINE EXP	58469	116,451	110,862	103,755
MAINT NON-ELECT UG EQUIP	59460	730,261	716,749	582,898
MAINT ELECT UG EQUIP	59462	3,292,892	3,536,493	4,251,254
Subtotal		**$17,649,870**	**$18,653,272**	**$18,051,840**
Network Costs (First Hill and U District 15.0%)				
INSPECT & TEST NETWORK UG DIST	58442	$253,352	$283,660	$447,221
MAINT NETWORK UG LINES	59440	2,188	3,147	8,964
MAINT NETWORK UG EQUIP	59442	770,155	411,925	999,493
MISC NETWK UG DIST SYS EXP	58841	3,639	200	3,617
Subtotal		**$1,029,334**	**$698,931**	**$1,459,296**
Subtotal x 15.0%	**15%**	**$154,400**	**$104,840**	**$218,894**
Total Non-network Rate Classes O&M Expenses		**$17,804,270**	**$18,758,111**	**$18,270,734**
Totals in $2014		**$18,369,666**	**$19,120,703**	**$18,270,734**
Three Year Average				$18,587,035
Total Capacity MW				5,603
Annual O&M Costs $2014/ MW				**$3,317**

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

FERC Code	FERC #	2012	2013	2014
Network Costs (Downtown Network 85.0%)				
INSPECT & TEST NETWORK UG DIST	58442	$253,352	$283,660	$447,221
MAINT NETWORK UG LINES	59440	2,188	3,147	8,964
MAINT NETWORK UG EQUIP	59442	770,155	411,925	999,493
MISC NETWK UG DIST SYS EXP	58841	3,639	200	3,617
Subtotal		$1,029,334	$698,931	$1,459,296
Subtotal x 85.0%	**85%**	**$874,934**	**$594,091**	**$1,240,401**
Total in $2014		**$902,718**	**$605,575**	**$1,240,401**
Three Year Average				$916,232
Total Capacity MW				660
Annual O&M Costs $2014/MW				**$1,388**

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 2017 and 2018 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	$24,285,435	$2,680,638	$614,557	$295,725	$151,119
Number of Meters	357,102	40,529	2,573	93	12
Capital Cost per Meter	68.01	66.14	238.82	3,164.64	12,593.21
O&M Cost per Meter	5.78	5.78	5.78	7.98	7.98
$2014/Meter	**$73.78**	**$71.92**	**$244.60**	**$3,172.62**	**$12,601.19**
Network					
Annualized Capital Cost	$1,642,681	$326,696	$138,402	$904,762	
Number of Meters	18,467	3,191	588	57	
Capital Cost per Meter	88.95	102.39	235.50	15,912.79	
O&M Cost per Meter	5.78	5.78	5.78	7.98	
$2014/Meter	**$94.73**	**$108.17**	**$241.27**	**$15,920.78**	

Table 3.29: 2017 and 2018 Service Drop Costs

		Residential	Small	Medium	Large	High Demand
Non-network Costs $2014/Meter		$73.78	$71.92	$244.60	$3,172.62	$12,601.19
Network Costs $2014/Meter		$94.73	$108.17	$241.27	$15,920.78	
2017 Costs for Service Drops				**$2017 inflation adjustment =**		**1.05801**
Non-network	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**
Number of Meters	423,548	379,557	41,228	2,656	95	12
$2017 Total	**$33,932,216**	**$29,629,065**	**$3,136,950**	**$687,332**	**$318,883**	**$159,986**
Network	**Total**	**Residential**	**Small**	**Medium**	**Large**	
Number of Meters	24,213	20,419	3,188	546	60	
$2017 Total	**$3,561,300**	**$2,046,432**	**$364,835**	**$139,376**	**$1,010,658**	
2018 Costs for Service Drops				**$2018 inflation adjustment =**		**1.08400**
Non-network	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**
Number of Meters	423,781	379,572	41,431	2,671	95	12
$2018 Total	**$34,786,771**	**$30,358,109**	**$3,229,835**	**$708,194**	**$326,716**	**$163,916**
Network	**Total**	**Residential**	**Small**	**Medium**	**Large**	
Number of Meters	24,233	20,419	3,204	549	61	
$2018 Total	**$3,668,703**	**$2,096,703**	**$375,673**	**$143,584**	**$1,052,743**	

Total Wires and Related Equipment Costs Including Service Drops

Total Wires and Related Equipment costs for 2017 and 2018 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: 2017 Total Wires and Related Equipment Costs

Non-network				**Network**			
Capital Costs, $2014/MW		$36,273		Capital Costs, $2014/MW		$129,000	
O&M Costs, $2014/MW		$3,317		O&M Costs, $2014/MW		$1,388	
Total Capacity MW		5,603		Total Capacity MW		660	
2017 Coincident Peak Load (MW)							
	Total	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Non-network	1,196.4	513.3	177.8	258.7	123.3	117.3	6.0
Network	192.4	14.3	23.5	69.1	85.3		
Service Territory	1,388.8						
2017 Wires and Related Equipment Costs					**$2017 inflation adjustment =**		**1.05801**
	Total	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Non-network	$268,628,679	$130,323,988	$38,012,690	$51,440,732	$24,506,619	$23,167,669	$1,176,981
Network	$94,609,586	$8,838,173	$11,500,860	$32,866,445	$41,404,108		
Service Territory	$363,238,265	$139,162,161	$49,513,550	$84,307,177	$65,910,727	$23,167,669	$1,176,981

Table 3.31: 2018 Total Wires and Related Equipment Costs

Non-network				**Network**			
Capital Costs, $2014/MW		$36,273		Capital Costs, $2014/MW		$129,000	
O&M Costs, $2014/MW		$3,317		O&M Costs, $2014/MW		$1,388	
Total Capacity MW		5,603		Total Capacity MW		660	
2018 Coincident Peak Load (MW)							
	Total	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Non-network	1,197.5	513.9	178.0	259.0	123.4	117.4	5.8
Network	192.6	14.4	23.6	69.2	85.4		
Service Territory	1,390.1						
2018 Wires and Related Equipment Costs					**$2018 inflation adjustment =**		**1.08400**
	Total	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Non-network	$275,248,606	$133,548,750	$38,969,968	$52,719,513	$25,113,943	$23,741,843	$1,154,589
Network	$96,953,611	$9,055,285	$11,785,257	$33,674,602	$42,438,468		
Service Territory	$372,202,218	$142,604,034	$50,755,225	$86,394,115	$67,552,411	$23,741,843	$1,154,589

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 2015 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.[5]

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, $2014

Customer Class	$/kW/Year
Residential	$3.20
Small	$3.91
Medium, Combined	$10.28
Medium, Non-network	$6.37
Medium, Network	$24.97
Large, Combined	$6.62
Large, Non-network	$2.78
Large, Network	$12.70
High Demand	$1.56
Streetlights	$3.91

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.

[5] 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), $2014

Transformer Type	Transformers	Network Protectors	Ancillary Equipment	Installation Cost	Total Cost
25 kVA, Overhead	$2,182		$321	$1,223	$3,726
25 kVA, Underground	$4,325		$538	$5,936	$10,799
50 kVA, Overhead	$1,404		$384	$1,223	$3,010
50 kVA, Underground	$5,428		$623	$5,936	$11,987
75 kVA, Overhead	$3,946		$440	$1,223	$5,609
75 kVA, Underground	$6,743		$961	$5,936	$13,639
100 kVA, Overhead	$5,340		$440	$1,223	$7,002
100 kVA, Underground	$7,638		$953	$7,966	$16,557
167 kVA, Overhead	$8,018		$891	$1,529	$10,437
167 kVA, Underground	$11,693		$1,536	$7,966	$21,196
750 kVA Commercial Subway	$101,695		$1,569	$11,247	$114,510
1000 kVA Commercial Subway	$56,450		$1,533	$11,247	$69,229
1500 kVA Commercial Subway	$69,619		$1,533	$11,247	$82,399
2000 kVA Commercial Subway	$83,951		$1,533	$11,247	$96,731
2500 kVA Commercial Subway	$106,607		$1,533	$11,247	$119,386
5000 kVA Commercial Subway	$140,482		$16,406	$50,556	$207,445
7500 kVA Commercial Subway	$183,258		$16,152	$40,720	$240,131
15000 kVA Commercial Subway	$434,502		$16,087	$40,720	$491,309
500 kVA Network	$47,435	$28,115	$9,176	$29,735	$114,461
750 kVA Network	$49,736	$27,212	$9,247	$29,735	$115,931
1000 kVA Network	$56,767	$26,100	$9,287	$29,735	$121,890
1500 kVA Network	$76,563	$36,277	$10,194	$31,619	$154,653
2000 kVA Network	$78,088	$53,475	$10,270	$31,619	$173,452

Transformer O&M Costs

Reported O&M costs vary year to year, so a three year average from 2012 to 2014, 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. In order 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 21.11% of the annual capital cost.

Class Load Factors Used in Transformer Cost Calculation

Similar to other areas of distribution costs, we first determine the cost per MW of transformers for each class. However, in the case of transformers, we arrive at a total cost by using the non-coincident maximum demand, or connected load, instead of the peak demand. This is because

transformers are installed in order to meet customer specific peak loads, regardless of the system peak.

Medium, Large and High Demand classes have demand meters; therefore, 2015 connected loads can be obtained directly from the billing records. For Residential and Small General Service classes, load factors are used to estimate 2015 non-coincident maximum demand (connected load). Load factors are necessary for all classes to forecast future connected load. **Table 3.34** details load factor assumptions.

Table 3.34: 2015 Load Factors by Customer Class

Customer Class	Adjusted Annual MWH	Connected Load, MW		Load Factor	
Residential	3,092,367	928.0	(1)	0.3804	(4)
Residential Non-network	3,011,488	903.5	(2)	0.3805	
Residential Network	80,879	24.5	(3)	0.3772	
Small	1,189,980	357.4	(1)	0.3801	(4)
Small Non-network	1,054,200	316.3	(2)	0.3805	
Small Network	135,780	41.1	(3)	0.3772	
Medium	2,390,145	723.3		0.3772	(4)
Medium Non-network	1,887,343	571.2		0.3772	(4)
Medium Network	502,803	152.2		0.3772	(4)
Large	1,505,832	468.6		0.3669	(4)
Large Non-network	900,126	287.3		0.3577	(4)
Large Network	605,707	181.3		0.3814	(4)
High Demand	1,070,708	342.3		0.3571	(4)
Streetlights	56,677	12.9		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 2015 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.[6] The load factor is calculated for each class by dividing 2015 average class energy consumption in MWh by 8,760 hours and then dividing the result by the total class non-coincident maximum demand for 2015.[7]

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.

[6] 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.

[7] 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, $2014

Total Residential Transformer Cost = $3.20 /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	$3,295	$355	$1,071	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			$1,404		
(h)	50 kVA UG Transformer			$5,428		
(i)	50 kVA OH Ancillary Equipment Cost			$384		
(j)	50 kVA UG Ancillary Equipment Cost			$623		
(k)	50 kVA OH Labor & Installation Cost			$1,223		
(l)	50 kVA UG Labor & Installation Cost			$5,936		
(m)	% Overhead transformers			80%		
Annual Capital Cost Calculations:						
Transformer Cost (TC) = (B) =			(g) * (m) + (h) * [1-(m)]		$2,209	
Ancillary Equipment and Material Cost (C) =			(i) * (m) + (j) * [1-(m)]		$432	
Installation Cost (D) =			(k) * (m) + (l) * [1-(m)]		$2,165	
Adjusted for Losses (TCAFL) =			TC * {1 / [1 - (e)]}		$2,248	
Annualized Capital Cost (ACC) =			{(a)*[(TCAFL)+ (C)] + (D)} *(c)		$240	/year
Levelized Capital Cost (LCC) =			ACC / [(A) * (d)]		$3.20	/kW/year

Table 3.36: Small General Service Class and Streetlight Transformer Cost, $2014

	Small General Service Class and Streetlight Transformer Cost =				$3.91 /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	$3,005	$339	$1,022	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			$1,404		
(h)	50 kVA UG Transformer Cost			$5,428		
(i)	50 kVA OH Ancillary Equipment Cost			$384		
(j)	50 kVA UG Ancillary Equipment Cost			$623		
(k)	50 kVA OH Labor & Installation Cost			$1,223		
(l)	50 kVA UG Labor & Installation Cost			$5,936		
(m)	% Overhead transformers			90%		
Annual Capital Cost Calculations:						
Transformer Cost (TC) = (B) =			(g) * (m) + (h) * [1-(m)]		$1,806	
Ancillary Equipment and Material Cost (C) =			(i) * (m) + (j) * [1-(m)]		$408	
Installation Cost (D) =			(k) * (m) + (l) * [1-(m)]		$1,694	
Adjusted for Losses (TCAFL) =			TC * {1 / [1 - (e)]}		$1,849	
Annualized Capital Cost (ACC) =			{(a) *[(TCAFL)+ (C)] + (D)} * (c)		$196	/year
Levelized Capital Cost (LCC) =			ACC / [(A) * (d)]		$3.91	/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, $2014

Medium General Service Transformer Cost, Combined =				**$10.28**	**/kW/year**
Medium General Service Transformer Cost, non-Network =				**$6.37**	**/kW/year**
Medium General Service Transformer Cost, Network =				**$24.97**	**/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	$2,611	$365	$2,165	1,842	46,050
(2)	50	$2,209	$432	$2,165	2,745	137,250
(3)	75	$4,506	$544	$2,165	1,215	91,125
(4)	100	$5,799	$542	$2,572	660	66,000
(5)	167	$8,753	$1,020	$2,816	789	131,763
% Overhead transformers		80%			**Total**	**472,188**
Commercial Subway						
(6)	750	$101,695	$1,569	$11,247	126	94,500
(7)	1,000	$56,450	$1,533	$11,247	59	59,000
(8)	1,500	$69,619	$1,533	$11,247	31	46,500
Network					**Total**	**200,000**
(9)	500	$47,435	$37,291	$29,735	505	252,500
(10)	750	$49,736	$36,459	$29,735	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	21.11%		
(g)	% of Capital Cost Subject to O&M	64.07%	30.99%	100.00%

Annual Capital and O&M Cost Calculations:	**Combined**	**Non-network**	**Network**
Annualized Transformer Cost (ATC) = {[(a)*SUM(1...10)(B*E)]}*(c)	$3,571,916	$2,264,774	$1,307,142
Adj. for Losses (AFL) = ATC / (1-d) [$/kW/yr]	$3,600,048	$2,287,188	$1,312,860
Ann. Mat'l & Install (AMIC)={(a)*SUM(1...10)(C*E)+SUM(1...10)(D*E)}*(c)	$2,951,799	$1,127,975	$1,823,824
Ann. Cap. Cost (ACC) = AFL+AMIC [$/ year]	$6,551,847	$3,415,163	$3,136,684
Levelized Cap.Cost (LCC) = ACC/(e) [$/kW/yr]	$9.06	$5.98	$20.61
Ann.O&M (AOM) = LCC * (f) *(g) [$/kW/yr]	$1.23	$0.39	$4.35
Total Cost = LCC + AOM [$/kW/yr]	**$10.28**	**$6.37**	**$24.97**

Table 3.38: Large General Service Class Transformer Cost, $2014

				Large General Service Transformer Cost, Combined =	**$6.62**	**/kW/year**
				Large General Service Transformer Cost, Non-Network =	**$2.78**	**/kW/year**
				Large General Service Transformer Cost, Network =	**$12.70**	**/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	$101,695	$1,569	$11,247	5	3,750
(2)	1,000	$56,450	$1,533	$11,247	5	5,000
(3)	1,500	$69,619	$1,533	$11,247	38	57,000
(4)	2,000	$83,951	$1,533	$11,247	48	96,000
(5)	2,500	$106,607	$1,533	$11,247	11	27,500
(6)	5,000	$140,482	$16,406	$50,556	7	35,000
(7)	7,500	$183,258	$16,152	$40,720	7	52,500
					Total	**276,750**
Network						
(8)	500	$44,876	$47,745	$55,563	0	0
(9)	750	$48,615	$47,768	$55,563	45	33,750
(10)	1,000	$59,108	$47,789	$55,563	12	12,000
(11)	1,500	$78,872	$59,835	$56,317	117	175,500
(12)	2,000	$91,874	$72,254	$56,317	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	21.11%		

Annual Capital and O&M Cost Calculations:	**Combined**	**Non-network**	**Network**
Annualized Transformer Cost (ATC) = {[(a)*SUM(1...12)(B*E)]}*(c)	$1,286,846	$544,203	$742,643
Adj. for Losses (AFL) = ATC / (1-d) [$/kW/yr]	$1,294,682	$549,090	$745,592
Ann. Mat'l & Install (AMIC)={(a)*SUM(1...12)(C*E)+SUM(1...12)(D*E)}*(c)	$1,264,732	$109,926	$1,154,805
Ann. Cap. Cost (ACC) = AFL+AMIC [$/ year]	$2,559,413	$659,016	$1,900,398
Levelized Cap.Cost (LCC) = ACC/(e) [$/kW/yr]	$5.46	$2.29	$10.48
Ann.O&M (AOM) = LCC * (f) [$/kW/yr]	$1.15	$0.48	$2.21
Total Cost = LCC + AOM [$/kW/yr]	**$6.62**	**$2.78**	**$12.70**

Table 3.39: High Demand General Service Class Transformer Cost, $2014

Total High Demand General Service Class Transformer Cost =				$1.56/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	$140,482	$16,406	$50,556	2	5,000
(2)	7,500	$183,258	$16,152	$40,720	0	7,500
(3)	15,000	$434,502	$16,087	$40,720	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			21.11%		
Annual Capital and O&M Cost Calculations:						
Annualized Transformer Cost (ATC) = {[(a) * SUM(1…3)(B * E)]} * (c)					$382,646	
Adj. for Losses (AFL) = ATC / (1-d) [$/kW/yr]					$386,082	
Ann. Mat'l & Install (AMIC) = (a)*SUM(1…3)(C*E)+SUM(1…3)(D*E)}*(c)					$54,197	
Ann. Cap. Cost (ACC) = AFL+AMIC [$/ year]					$440,279	
Levelized Cap.Cost (LCC) = ACC/(e) [$/kW/yr]					$1.29	
Ann.O&M (AOM) = LCC * (f) [$/kW/yr]					$0.27	
Total Cost = LCC +AOM [$/kW/yr]					**$1.56**	

Total Transformer Costs

Table 3.40 presents total transformer costs for 2017 and 2018. 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: 2017 and 2018 Total Transformer Costs

	Residential	Small	Medium	Large	High Demand	Lights
Non-network Transformer Costs $2014/kW	$3.20	$3.91	$6.37	$2.78	$1.56	$3.91
Network Transformer Costs* $2014/kW	$18.83	$18.83	$24.97	$12.70		

2017 Transformer Costs — $2017 inflation adjustment = 1.05801

Total Non-network	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Load, MWh	8,068,223	3,030,311	1,060,358	1,904,426	928,426	1,085,520	59,183
Load Factor		0.3805	0.3805	0.3772	0.3577	0.3571	0.5000
Peak Load, MW	2,460	909	318	576	296	347	14
$2017 Total Costs	$9,778,264	$3,077,466	$1,317,437	$3,884,517	$870,915	$571,972	$55,957
Downtown Network	**Total**	**Residential**	**Small**	**Medium**	**Large**		
Load, MWh	1,363,977	87,289	138,441	507,328	630,918		
Load Factor		0.3772	0.3772	0.3772	0.3814		
Peak Load, MW	411	26	42	154	189		
$2017 Total Costs	$7,953,026	$526,307	$834,733	$4,055,483	$2,536,502		
Total Service Territory	**$17,731,289**	**$3,603,773**	**$2,152,170**	**$7,940,000**	**$3,407,417**	**$571,972**	**$55,957**

2018 Transformer Costs — $2018 inflation adjustment = 1.08400

Total Non-network	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Load, MWh	8,085,731	3,023,410	1,065,595	1,914,114	933,321	1,092,785	56,507
Load Factor		0.3805	0.3805	0.3772	0.3577	0.3571	0.5000
Peak Load, MW	2,466	907	320	579	298	349	13
$2018 Total Costs	$10,044,235	$3,145,884	$1,356,466	$4,000,188	$897,014	$589,944	$54,739
Downtown Network	**Total**	**Residential**	**Small**	**Medium**	**Large**		
Load, MWh	1,370,369	87,090	139,125	509,909	634,245		
Load Factor		0.3772	0.3772	0.3772	0.3814		
Peak Load, MW	413	26	42	154	190		
$2018 Total Costs	$8,186,229	$538,008	$859,462	$4,176,244	$2,612,514		
Total Service Territory	**$18,230,464**	**$3,683,892**	**$2,215,929**	**$8,176,432**	**$3,509,528**	**$589,944**	**$54,739**

* 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. A small methodology change in this rate case was including meter costs in customer costs, previously it was in distribution costs. 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 2014 marginal customer service costs per meter, converting them into $2017 and $2018 and then multiplying them by the number of meters projected in 2017 and 2018.

Table 3.41: 2014 Customer Service Costs by FERC Code

FERC Code[8]	FERC #	2014
Revenue		
MISC SVC REV-MISC COML EQ RENT	45110	$154,799
MISC SVC REV-ACCT CHANGE FEE(R	45130	1,732,004
MISC SVC REV-ACCT CHANGE FEE(C	45131	6,959
MISC SVC REV-RECONCT & FIELD C	45150	1,040,272
Total		**$2,934,033**
Expenses		
METER READING SUPERVISION	90101	$302,113
METER READING EXPENSES	90201	4,165,607
DISCON SERV NON-PAYMENT	90301	1,310,722
CR INVESTIGATIONS & RECORDS	90311	2,456,152
COLLECTING-LIGHT DEPT	90321	4,168,418
COL-CITY TREAS BNKS,AM EXPR	90341	2,289,087
CUST CONTR & ORDERS	90351	9,389,805
BILL REV ACCTG & MAILING	90361	3,481,321
UNCOLLECTIBLE ACCT-ELEC UTILTY[9]	90401	4,935,090
UNCOLLECTIBLE ACCT-SUNDRY SALE[2]	90403	1,291,864
MISC CUST ACCT EXP	90501	1,132,652
SUPERVISION-RESIDENTIAL	90701	258,645
SUPV-CMML & IND	90711	38,414
CUST ASST EXP- RESDL	90801	3,808,792
CUST ASST EXP-CMML& IND	90811	1,843,869
MISC CUST SERV & INFO EXP	91001	888,316
GENERAL ADVERTISING EXPENSES[2]	93010	46,097
Total		**$41,806,964**

[8] FERC Names are listed as they appear in the system; some line items may look abbreviated or truncated.
[9] Value is a four year average (2010-2013) because of large year-to-year variation.

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: 2014 Customer Information Data

	Total	Residential	Small	Medium	Large	High Demand
Meter Count	422,613	375,569	43,720	3,161	150	12
Non-network		357,102	40,529	2,573	93	12
Network		18,467	3,191	588	57	
Customer Count[10]	391,606	356,405	32,255	2,803	134	9
Bills Issued Count (Annual Average)	2,814,064	2,508,226	269,209	34,742	1,766	121
Annual kWh Consumption	9,446,274	3,092,367	1,208,604	2,453,662	1,526,245	1,165,395
Payment						
Cash or Check	$495,520,660	$147,092,776	$69,435,295	$137,362,317	$90,700,689	$50,929,583
Credit Card	$41,861,362	$33,620,259	$4,687,336	$2,024,463	$1,179,014	$350,290
Web/Metavante	$160,229,317	$82,872,447	$16,376,717	$29,101,010	$14,639,502	$17,239,641
Interfund transfer	$14,034,148	$731,226	$1,830,405	$6,730,036	$4,742,480	$0
Uncollectibles	$2,874,261	$2,694,183	$154,308	$25,770	$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.
iv. In a case when customers have multiple meters on one account (which may be billed under more than one class' rate schedule), the larger class (in terms of maximum demand definition) is assigned the account.

[10] Based on 2012 data.

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. Weighting factors considered whether the route was walk or drive, and the number of meter reads per year. Weighting factors have not changed since the 2007-2008 COSACAR because little has changed in the logistics of the meter reading activities since that time. 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	422,613	375,569	43,720	3,161	150	
Non-network		357,102	40,529	2,573	93	
Network		18,467	3,191	588	57	
Meter Reading						
Non-network		1.00	1.18	2.98	1.00	1.00
Network		1.78	1.70	2.13	1.00	
Weighted Meter	452,305	389,974	53,249	8,920	150	
Non-network		357,102	47,825	7,668	93	
Network		32,871	5,424	1,252	57	

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		78.98%	10.58	1.70%		
Network		7.27%	1.20%	0.28%		
MR_L_H	100%					
Non-network					57.57%	7.39%
Network					35.03%	
MR_ALL	100%					
Non-network		78.95%	10.57	1.70%	0.02%	0.0027%
Network		7.27%	1.20%	0.28%	0.01%	
METER COUNT						
MC_R_S_M	100%	88.90%	10.35	0.75%		
MC_L_H	100%				92.61%	7.39%
MC_ALL	100%	88.87%	10.35	0.75%	0.04%	0.00%
Wgt. Avg. MC_ALL and MC_L_H (2/3 to R, S,& M, and 1/3 to L & HD)	100%	59.27%	6.90%	0.50%	30.87%	2.46%
CUSTOMER COUNT						
C_R_S_M	100%	91.04%	8.24%	0.72%		
C_S_M	100%		92.00	8.00%		
C_L_H	100%				93.71%	6.29%
C_S_M_L_H	100%		91.63	7.96%	0.38%	0.03%
C_ALL	100%	91.01%	8.24%	0.72%	0.03%	0.00%
BILLS ISSUED						
BI_R_S_M	100%	89.19%	9.57%	1.24%		
BI_ALL	100%	89.13%	9.57%	1.23%	0.06%	0.00%
BI_L_H	100%				93.59%	6.41%
kWh RELATED						
kWh	100%	32.74%	12.79	25.97%	16.16%	12.34%
PAYMENT METHOD						
Cash or Check	100%	29.68%	14.01	27.72%	18.30%	10.28%
Credit Card	100%	80.31%	11.20	4.84%	2.82%	
Metavante	100%	51.72%	10.22	18.16%	9.14%	10.76%
Average of Credit Card and Metavante	100%	66.02%	10.71	11.50%	5.98%	5.80%
OTHER						
EU_BAD_DEBT	100%	93.73%	5.37%	0.90%		
EUC_BAD_DEBT	100%		85.69	14.31%		

Customer Service Costs per Meter Computations

The results of 2014 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.

Over 91 percent of the labor expenditures for program code 90201 originated from Organization (Org) Units 472-Meter Reading and 473-Technical Metering[11]. An allocation subtotal was computed for these organization units. The remaining 9 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		$302,113					
Non-network	MR_ALL		$238,523	$31,944	$5,122	$62	$8
Network	MR_ALL		$21,956	$3,623	$836	$38	
FERC 90201							
Labor							
472 Meter Reading		$3,476,715					
Non-network	MR_R_S_M		$2,745,909	$367,743	$58,966		
Network	MR_R_S_M		$252,762	$41,709	$9,626		
473 Technical		$126,918					
Non-network	MR_L_H					$73,073	$9,384
Network	MR_L_H					$44,461	
Non-Labor							
472 Meter Reading		$104,860					
Non-network	MR_ALL		$82,789	$11,087	$1,778	$22	$3
Network	MR_ALL		$7,621	$1,258	$290	$13	
Total Allocated		$3,708,493					
Non-network			$2,828,698	$378,830	$60,743	$73,095	$9,386
Network			$260,383	$42,966	$9,916	$44,474	
Overall Allocation							
Non-network			76.28%	10.22%	1.64%	1.97%	0.25%
Network			7.02%	1.16%	0.27%	1.20%	
Total FERC 90201		$4,165,607					
Non-network			$3,177,367.9	$425,525.4	$68,230.8	$82,104.3	$10,543.5
Network			$292,478.4	$48,262.4	$11,138.2	$49,956.4	
Total FERC 90101 and 90201		$4,467,720					
Non-network			$3,415,891	$457,469	$73,353	$82,167	$10,551
Network			$314,435	$51,885	$11,974	$49,994	
Meters							
Non-network			357,102	40,529	2,573	93	12
Network			18,467	3,191	588	57	
$2014/Meter							
Non-network			$9.57	$11.29	$28.51	$879.29	$879.29
Network			$17.03	$16.26	$20.37	$879.29	

[11] 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.

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	$1,310,72	$1,228,603	$70,367	$11,752	$0	$0
FERC 90401	EU_BAD_DEBT	$4,935,09	$4,625,897	$264,945	$44,247	$0	$0
FERC 90403	EU_BAD_DEBT	$1,291,86	$1,210,926	$69,355	$11,583	$0	$0
Total		$7,537,67	$7,065,427	$404,668	$67,581	$0	$0
Meters			375,569	43,720	3,161	150	12
$2014/Meter			$18.81	$9.26	$21.38	$0.00	$0.00

Org. Units 463 and 464 contributed over 99.9% 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. Non-labor expenditures were directly allocated to the Residential class because for both Org. Units at least 98% of non-labor costs (93% for Org. Unit 463 and over 99% for Org. Unit 464) were related to Residential customers.[12] **Table 3.47** has detailed results.

[12] Org. Unit 463 had non-labor charges of $236,760 for Project Share and $6,536 for the Department of Information Technology (DoIT) activity billing charges. The DoIT Activity Billing was related to billing the small customers, 91% of which were Residential class. Project Share charges represented 91% of the total non-labor charges and were Residential class low-income assistance program-related. Org. Unit 464 had $1.54 million of non-labor charges, of which $1.5 million (97%) was for interfund payment for the Dept. of Neighborhoods Pay Center Bill Acceptance program and for the Human Services Department (HSD) for the Mayor's Office for Senior Citizens (MOSC). These charges were directly related to Residential customer count. The remaining percentage of non-labor charges was related to DoIT Activity Billing and postage and delivery. These expenditures were related to customer count, with the Residential class making up over 91%.

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	$328,627	$299,196	$27,078	$2,353		
464 Customer	C_R_S_M	$327,452	$298,126	$26,981	$2,345		
Non-Labor							
463 Credit	DIRECT:RES	$259,857	$259,857				
464 Customer	DIRECT:RES	$1,538,796	$1,538,796				
Total Allocated		$2,454,731	$2,395,975	$54,058	$4,698		
Overall Allocation Ratios			97.61%	2.20%	0.19%		
Total FERC 90311		$2,456,250	$2,397,458	$54,092	$4,701		
Meters		375,569	43,720	3,161	150	12	
$2014/Meter		$6.38	$1.24	$1.49			

Collecting-Light Department

The total dollars allocated in **Table 3.48** represent over 98% 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 $4,168,418 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	$166,007	$151,140	$13,678	$1,189	$0	$0
352 South Customer	C_R_S_M	$92,440	$84,162	$7,617	$662	$0	$0
430 Customer Care	C_R_S_M	$349	$318	$29	$2	$0	$0
431 Account Executives	C_L_H	$0	$0	$0	$0	$0	$0
463 Credit	C_R_S_M	$1,361,200	$1,239,296	$112,157	$9,747	$0	$0
464 Customer Accounts	C_R_S_M	$219,748	$200,068	$18,106	$1,573	$0	$0
473 Technical Metering	C_L_H	$3,261	$0	$0	$0	$3,056	$205
522 IT Operations	C_ALL	$131,784	$119,938	$10,855	$943	$45	$3
523 IT Applic Dev Serv	C_ALL	$647,481	$589,279	$53,330	$4,634	$222	$15
000 Financial Statement	C_ALL	-$40,958	-$37,277	-$3,374	-$293	-$14	-$1
Non-Labor							
430 Customer Care	C_ALL	$202	$184	$17	$1	$0	$0
463 Credit	C_R_S_M	$69,563	$63,333	$5,732	$498	$0	$0
523 IT Applic Dev Serv	C_ALL	$1,452,348	$1,321,799	$119,624	$10,395	$497	$33
831 General Expenses	C_ALL	$0	$0	$0	$0	$0	$0
Total Allocated		$4,103,426	$3,732,240	$337,771	$29,353	$3,806	$256
Overall Allocation Ratios			90.95%	8.23%	0.72%	0.09%	0.01%
Total FERC 90321		$4,168,418	$3,791,353	$343,121	$29,818	$3,866	$260
Meters			375,569	43,720	3,161	150	12
$2014/Meter			$10.09	$7.85	$9.43	$25.72	$21.64

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 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	$2,289,087	$1,511,192	$245,139	$263,225	$136,808	$132,723
Meters			375,569	43,720	3,161	150	12
$2014/Meter			$4.02	$5.61	$83.27	$910.21	$11,060.24

Customer Contracts and Orders

Org Unit 464-Customer Accounts, contributed 98.5% 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 over 99% 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	$773,746	$704,452	$63,754	$5,540	$0	$0
352 South Customer Eng	C_R_S_M	$694,770	$632,549	$57,246	$4,975	$0	$0
430 CC Director's Office	C_ALL	$268	$244	$22	$2	$0	$0
463 Credit	C_R_S_M	$727,966	$662,772	$59,982	$5,212	$0	$0
464 Customer Accounts	C_R_S_M	$1,834,69	$1,670,388	$151,172	$13,137	$0	$0
Non-Labor							
341 North Customer Eng	C_R_S_M	$32,945	$29,995	$2,715	$236	$0	$0
352 South Customer Eng	C_R_S_M	$38,968	$35,478	$3,211	$279	$0	$0
430 CC Director's Office	C_ALL	$84	$76	$7	$1	$0	$0
464 Customer Accounts	C_R_S_M	$5,284,79	$4,811,508	$435,446	$37,841	$0	$0
Total Allocated		$9,388,23	$8,547,461	$773,554	$67,223	$0	$0
Overall Allocation Ratios			91.04%	8.24%	0.72%	0%	0%
Total FERC 90351		$9,389,80	$8,548,888	$773,683	$67,234	$0	$0
Meters				43,720	3,161	150	12
$2014/Meter			$22.76	$17.70	$21.27	$0.00	$0.00

Bill Revenue Accounting and Mailing

Expenditures from the seven Org Units shown in **Table 3.51** contributed over 99% 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 $3,481,321 to compute the final class allocations.[13]

[13] 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	$5,697	$5,081	$545	$70	$0	$0
352 South Customer Eng	BI_R_S_M	$27,595	$24,613	$2,642	$341	$0	$0
431 Account Executives Office	BI_L_H	$7,732	$0	$0	$0	$7,236	$496
464 Customer Accounts	BI_R_S_M	$1,327,211	$1,183,761	$127,054	$16,397	$0	$0
543 General Accounting	BI_ALL	$315,364	$281,090	$30,169	$3,893	$198	$14
Non-Labor							
463 Credit	BI_ALL	$123,461	$110,043	$11,811	$1,524	$77	$5
464 Customer Accounts	BI_ALL	$1,267,033	$1,129,330	$121,211	$15,643	$795	$54
580 Office Supplies	BI_ALL	$418,663	$373,162	$40,052	$5,169	$263	$18
Total Allocated		$3,492,756	$3,107,078	$333,484	$43,037	$8,569	$587
Overall Allocation Ratios			88.96%	9.55%	1.23%	0.25%	0.02%
Total FERC 90361		$3,481,321	$3,096,906	$332,392	$42,896	$8,541	$585
Meters			375,569	43,720	3,161	150	12
$2014/Meter			$8.25	$7.60	$13.57	$56.83	$48.77

Miscellaneous Customer Accounting Expenses

Expenditures from eight Org. Units shown in **Table 3.52** contributed 90% of the charges to FERC 90501. Ratios were developed from this overall factor and applied to the program code total of $1,132,652 to compute the final class allocations.

Supervision Expenses

FERC Program Code 90701 costs were directly assigned to the Residential class and FERC Program Code 90711 was assigned to the commercial classes as seen in **Table 3.53**.

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**.

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	$43,537	$39,623	$3,586	$312	$15	$1
430 Customer Care	C_ALL	$194,305	$176,839	$16,004	$1,391	$66	$4
431 Account Executives	C_L_HD	$241	$0	$0	$0	$226	$15
463 Credit	C_R_S_M	$66,894	$60,904	$5,512	$479	$0	$0
464 Customer Accounts	C_R_S_M	$27,516	$25,052	$2,267	$197	$0	$0
472 Meter Reading	C_R_S_M	$330	$301	$27	$2	$0	$0
473 Technical Metering	C_L_HD	$197,371	$0	$0	$0	$184,949	$12,422
580 Office Services	C_ALL	$134,944	$122,814	$11,115	$966	$46	$3
Non-Labor							
317 Bus Plang and Implementation	C_ALL	$24,756	$22,530	$2,039	$177	$8	$1
430 Customer Care	C_ALL	$324,452	$295,288	$26,724	$2,322	$111	$7
473 Technical Metering	C_L_HD	$0	$0	$0	$0	$0	$0
Total Allocated		$1,014,346	$743,351	$67,274	$5,846	$185,422	$12,454
Overall Allocation Ratios			73.28%	6.63%	0.58%	18.28%	1.23%
Total FERC 90501		$1,132,652	$830,049	$75,120	$6,528	$207,048	$13,906
Meters			375,569	43,720	3,161	150	12
$2014/Meter			$2.21	$1.72	$2.07	$1,377.53	$1,158.85

Table 3.53: Supervision-Residential (FERC 90701)

	Allocation Factor	Total	Residential	Small	Medium	Large	High Demand
FERC 90701	DIRECT: RESID	$258,645	$258,645	$0	$0	$0	$0
FERC 90711	C_S_M_L_H	$38,414	$0	$35,199	$3,059	$146	$10
Total FERC 90701 & 90711		$297,059	$258,645	$35,199	$3,059	$146	$10
Meters			375,569	43,720	3,161	150	12
$2014/Meter			$0.69	$0.81	$0.97	$0.97	$0.82

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	$3,808,792	$3,808,792				
FERC 90811							
Labor							
341 North Customer Eng	C_S_M	$225,406	$0	$207,384	$18,022	$0	$0
352 South Customer Eng	C_S_M	$226,674	$0	$208,551	$18,123	$0	$0
398 Cust Svc O-M		$109,859	$0	$100,665	$8,748	$418	$28
431 Account Executives	C_L_HD	$195,924	$0	$0	$0	$183,594	$12,331
000 Financial Statement	C_S_M_L_H	$811,810	$0	$743,869	$64,643	$3,090	$208
Non-Labor							
341 North Customer Eng	C_S_M	$0	$0	$0	$0	$0	$0
352 South Customer Eng	C_S_M	$0	$0	$0	$0	$0	$0
484 Division Support		$81,500	$0	$74,679	$6,490	$310	$21
Total Allocated		$1,651,174	$0	$1,335,148	$116,026	$187,412	$12,587
Overall Allocation Ratios			0.00%	80.86%	7.03%	11.35%	0.76%
Total FERC 90811		$1,843,869	$0	$1,490,962	$129,567	$209,284	$14,056
Total FERC 90801 & 90811		$5,652,661	$3,808,792	$1,490,962	$129,567	$209,284	$14,056
Meters			375,569	43,720	3,161	150	12
$2014/Meter			$10.14	$34.10	$40.99	$1,392.40	$1,171.36

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 98% of the total charges to this account. Ratios were developed from this overall factor and applied to the program code total of $888,361 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	$821,11	$747,303	$67,63	$5,877	$281	$19
473 Technical	C_ALL	$16,454	$14,975	$1,355	$118	$6	$0
Non-Labor							
430 Customer Care	C_R_S_M	$0	$0	$0	$0	$0	$0
431 Account	C_ALL	$9,574	$8,713	$789	$69	$3	$0
831 General Expenses	C_ALL	$5,424	$4,937	$447	$39	$2	$0
Total Allocated		$852,56	$775,928	$70,22	$6,102	$292	$20
Overall Allocation			91.01%	8.24%	0.72%	0.03	0.00%
Total FERC 91001		$888,31	$808,466	$73,16	$6,358	$304	$20
Meters			375,569	43,720	3,161	150	12
$2014/Meter			$2.15	$1.67	$2.01	$2.02	$1.70

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	$46,09	$41,954	$3,797	$330	$16	$1
Meters			375,569	43,720	3,161	150	12
$2014/Meter			$0.11	$0.09	$0.10	$0.10	$0.09

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	C_S_M_L_H	-$154,799	$0	-$141,844	-$12,326	-$589	-$40
FERC	DIRECT: RESID	-$1,732,004	-$1,732,004	$0	$0	$0	$0
FERC	C_S_M_L_H	-$6,959	$0	-$6,377	-$554	-$26	-$2
FERC	EUC_BAD_DEB	-$1,040,272	$0	-$891,403	-$148,869	$0	$0
Total		-$2,934,033	-$1,732,004	-$1,039,623	-$161,749	-$616	-$41
Meters			375,569	43,720	3,161	150	12
$2014/Meter			-$4.61	-$23.78	-$51.17	-$4.10	-$3.45

Tables 3.58 and **3.59** summarizes the derivation of the 2014 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: 2014 Non-network Customer Service Costs per Meter by Customer Class

FERC #	Residential	Small	Medium	Large	High Demand
90101 and 90201	$9.57	$11.29	$28.51	$879.29	$879.29
90301 & 90401 &	$18.81	$9.26	$21.38	$0.00	$0.00
90311	$6.38	$1.24	$1.49	$0.00	$0.00
90321	$10.09	$7.85	$9.43	$25.72	$21.64
90341	$4.02	$5.61	$83.27	$910.21	$11,060.24
90351	$22.76	$17.70	$21.27	$0.00	$0.00
90361	$8.25	$7.60	$13.57	$56.83	$48.77
90501	$2.21	$1.72	$2.07	$1,377.53	$1,158.85
90701 & 90711	$0.69	$0.81	$0.97	$0.97	$0.82
90801 & 90811	$10.14	$34.10	$40.99	$1,392.40	$1,171.36
91001	$2.15	$1.67	$2.01	$2.02	$1.70
93010	$0.11	$0.09	$0.10	$0.10	$0.09
Subtotal	**$95.19**	**$98.92**	**$225.06**	**$4,645.08**	**$14,342.76**
451XX	-$4.61	-$23.78	-$51.17	-$4.10	-$3.45
$2014 Cost per Meter	**$90.58**	**$75.14**	**$173.89**	**$4,640.98**	**$14,339.32**

Table 3.59: 2014 Network Customer Service Costs per Meter by Customer Class

FERC #	Residential	Small	Medium	Large
90101 & 90201	$17.03	$16.26	$20.37	$879.29
90301 & 90401 &	$18.81	$9.26	$21.38	$0.00
90311	$6.38	$1.24	$1.49	$0.00
90321	$10.09	$7.85	$9.43	$25.72
90341	$4.02	$5.61	$83.27	$910.21
90351	$22.76	$17.70	$21.27	$0.00
90361	$8.25	$7.60	$13.57	$56.83
90501	$2.21	$1.72	$2.07	$1,377.53
90701 & 90711	$0.69	$0.81	$0.97	$0.97
90801 & 90811	$10.14	$34.10	$40.99	$1,392.40
91001	$2.15	$1.67	$2.01	$2.02
93010	$0.11	$0.09	$0.10	$0.10
Subtotal	**$102.65**	**$103.90**	**$216.93**	**$4,645.08**
451XX	-$4.61	-$23.78	-$51.17	-$4.10
$2014 Cost per Meter	**$98.04**	**$80.12**	**$165.76**	**$4,640.98**

Total Customer Service Costs

Table 3.60 shows total customer service costs by customer class in 2017 and 2018, which were derived by inflating 2014 per meter costs and then multiplying them by the projected number of meters.

Table 3.60: 2017 and 2018 Customer Service Costs by Customer Class

		Residential	**Small**	**Medium**	**Large**	**High Demand**
Non-network $2014 Costs per Meter		$90.58	$75.14	$173.89	$4,640.98	$14,339.32
Network $2014 Costs per Meter		$98.04	$80.12	$165.76	$4,640.98	
2017 Customer Costs				$2017 inflation adjustment =		1.05801
Total Non-network	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**
2017 Meters	423,548	379,557	41,228	2,656	95	12
$2017 Total Costs	$40,790,034	$36,375,225	$3,277,657	$488,631	$466,469	$182,053
Downtown Network	**Total**	**Residential**	**Small**	**Medium**	**Large**	
2017 Meters	24,213	20,419	3,188	546	60	
$2017 Total Costs	$2,778,651	$2,118,062	$270,226	$95,752	$294,612	
Total Service Territory	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**
$2017 Total Cost	$43,568,685	$38,493,287	$3,547,882	$584,383	$761,080	$182,053
2018 Customer Costs				$2018 inflation adjustment =		1.08400
Total Non-network	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**
2018 Meters	423,781	379,572	41,431	2,671	95	12
$2018 Total Costs	$41,812,886	$37,270,264	$3,374,708	$503,462	$477,927	$186,525
Downtown Network	**Total**	**Residential**	**Small**	**Medium**	**Large**	
2018 Meters	24,233	20,419	3,204	549	61	
$2018 Total Costs	$2,853,869	$2,170,093	$278,253	$98,643	$306,880	
Total Service Territory	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**
$2018 Total Cost	$44,666,755	$39,440,356	$3,652,961	$602,105	$784,807	$186,525

3.4.5 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 capital costs are annualized over the assumed economic life of the meters of 18 years and the cost of installation is annualized over 40 years. **Table 3.61** summarizes the $2014 annualized capital and O&M costs per meter and shows the total costs of meters by customer class for 2017 and 2018.

Table 3.61: 2017 and 2018 Total Meter Costs

Non-network		**Residential**	**Small**	**Medium**	**Large**	**High Demand**
Annualized Capital Cost		$2,478,836	$666,84	$176,581	$21,824	$4,220
Number of Meters		357,102	40,529	2,573	93	12
$2014 Capital Cost per		$6.94	$16.45	$68.62	$233.55	$351.64
$2014 O&M Cost per		$2.88	$2.88	$2.88	$3,732.87	$3,732.87
Total $2014 Cost per Non-network		$9.82	$19.34	$71.50	$3,966.42	$4,084.51
Network		**Residential**	**Small**	**Medium**	**Large**	**High Demand**
Annualized Capital Cost		$140,891	$97,463	$40,329	$13,435	
Number of Meters		18,467	3,191	588	57	
$2014 Capital Cost per		$7.63	$30.55	$68.62	$236.29	
$2014 O&M Cost per		$2.88	$2.88	$2.88	$3,732.87	
Total $2014 Cost per Network Meter		$10.51	$33.43	$71.50	$3,969.17	
2017 Meter Costs				**$2017 inflation adjustment =**		**1.05801**
Total Non-network	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**
2017 Number of Meters	423,548	379,557	41,228	2,656	95	12
2017 Total Costs	$5,440,01	$3,945,132	$843,431	$200,929	$398,668	$51,857
Total Network	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High**
2017 Number of Meters	24,213	20,419	3,188	546	60	
2017 Total Costs	$633,116	$227,094	$112,752	$41,305	$251,965	
Total Service Territory	$6,073,13	$4,172,226	$956,183	$242,234	$650,632	$51,857
2018 Meter Costs				**$2018 inflation adjustment =**		**1.08400**
Total Non-network	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**
2018 Number of Meters	423,781	379,572	41,431	2,671	95	12
2018 Total Costs	$5,579,23	$4,042,205	$868,405	$207,027	$408,461	$53,131
Total Network	**Total**	**Residential**	**Small**	**Medium**	**Large**	
2018 Number of Meters	24,233	20,419	3,204	549	61	
2018 Total Costs	$653,783	$232,672	$116,102	$42,553	$262,457	
Total Service Territory	$6,233,01	$4,274,877	$984,507	$249,580	$670,918	$53,131

3.4.6 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: 2017 and 2018 Total Customer Costs

2017						
Non-network	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**
2017 Customer Costs	$40,790,034	$36,375,225	$3,277,657	$488,631	$466,469	$182,053
2017 Meter Costs	$5,440,017	$3,945,132	$843,431	$200,929	$398,668	$51,857
Total	$46,230,051	$40,320,357	$4,121,087	$689,560	$865,136	$233,911
Network	**Total**	**Residential**	**Small**	**Medium**	**Large**	
2017 Customer Costs	$2,778,651	$2,118,062	$270,226	$95,752	$294,612	
2017 Meter Costs	$633,116	$227,094	$112,752	$41,305	$251,965	
Total	$3,411,767	$2,345,156	$382,978	$137,057	$546,576	
2018						
Non-network	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**
2018 Customer Costs	$41,812,886	$37,270,264	$3,374,708	$503,462	$477,927	$186,525
2018 Meter Costs	$5,579,230	$4,042,205	$868,405	$207,027	$408,461	$53,131
Total	$47,392,116	$41,312,469	$4,243,113	$710,489	$886,389	$239,657
Network	**Total**	**Residential**	**Small**	**Medium**	**Large**	
2018 Customer Costs	$2,853,869	$2,170,093	$278,253	$98,643	$306,880	
2018 Meter Costs	$653,783	$232,672	$116,102	$42,553	$262,457	
Total	$3,507,652	$2,402,765	$394,355	$141,196	$569,336	

3.6 Summary of Allocation Factors

Tables 3.63 and **3.64** summarize 2017 and 2018 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 2017 and 2018.

Table 3.63: 2017 Total Energy, Distribution and Customer Costs by Customer Class

Total Service Territory	Total	Residential	Small	Medium	Large	High Demand	Lights
Energy	$309,011,176	$102,288,259	$39,409,748	$79,312,587	$50,983,822	$35,148,357	$1,868,403
Distribution							
ISA Transmission	$52,699,662	$20,023,154	$7,639,230	$12,441,621	$7,917,322	$4,450,658	$227,678
Stations	$48,283,035	$18,157,689	$6,985,107	$11,474,618	$7,433,839	$4,025,836	$205,946
Wires & Related Equip.	$363,238,265	$139,162,161	$49,513,550	$84,307,177	$65,910,727	$23,167,669	$1,176,981
Transformers	$17,731,289	$3,603,773	$2,152,170	$7,940,000	$3,407,417	$571,972	$55,957
Streetlights							
Customer Costs	$49,641,819	$42,665,513	$4,504,065	$826,617	$1,411,713	$233,911	
Non-network	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Energy	$264,283,838	$99,424,324	$34,858,577	$62,628,662	$30,355,516	$35,148,357	$1,868,403
Distribution							
ISA Transmission	$45,400,210	$19,478,652	$6,746,441	$9,817,851	$4,678,930	$4,450,658	$227,678
Stations	$41,066,696	$17,619,387	$6,102,484	$8,880,724	$4,232,319	$4,025,836	$205,946
Wires & Related Equip.	$268,628,679	$130,323,988	$38,012,690	$51,440,732	$24,506,619	$23,167,669	$1,176,981
Transformers	$9,778,264	$3,077,466	$1,317,437	$3,884,517	$870,915	$571,972	$55,957
Streetlights							
Customer Costs	$46,230,051	$40,320,357	$4,121,087	$689,560	$865,136	$233,911	
Network	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Energy	$44,727,338	$2,863,935	$4,551,171	$16,683,925	$20,628,306		
Distribution							
ISA Transmission	$7,299,453	$544,502	$892,789	$2,623,769	$3,238,392		
Stations	$7,216,339	$538,302	$882,623	$2,593,894	$3,201,519		
Wires & Related Equip.	$94,609,586	$8,838,173	$11,500,860	$32,866,445	$41,404,108		
Transformers	$7,953,026	$526,307	$834,733	$4,055,483	$2,536,502		
Streetlights							
Customer Costs	$3,411,767	$2,345,156	$382,978	$137,057	$546,576		

Table 3.64: 2018 Total Energy, Distribution and Customer Costs by Customer Class

Total Service Territory	Total	Residential	Small	Medium	Large	High Demand	Lights
Energy	$373,648,774	$122,532,212	$47,675,884	$96,335,012	$61,987,990	$42,967,049	$2,150,627
Distribution							
ISA Transmission	$53,994,242	$20,518,554	$7,828,316	$12,749,713	$8,113,564	$4,560,759	$223,336
Stations	$49,469,297	$18,606,941	$7,158,010	$11,758,785	$7,618,116	$4,125,428	$202,018
Wires & Related Equip.	$372,202,218	$142,604,034	$50,755,225	$86,394,115	$67,552,411	$23,741,843	$1,154,589
Transformers	$18,230,464	$3,683,892	$2,215,929	$8,176,432	$3,509,528	$589,944	$54,739
Streetlights							
Customer Costs	$50,899,768	$43,715,233	$4,637,468	$851,685	$1,455,725	$239,657	
Non-network	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Energy	$319,366,911	$119,101,473	$42,170,111	$76,070,308	$36,907,343	$42,967,049	$2,150,627
Distribution							
ISA Transmission	$46,513,353	$19,960,518	$6,913,336	$10,060,727	$4,794,678	$4,560,759	$223,336
Stations	$42,073,588	$18,055,258	$6,253,448	$9,100,416	$4,337,019	$4,125,428	$202,018
Wires & Related Equip.	$275,248,606	$133,548,750	$38,969,968	$52,719,513	$25,113,943	$23,741,843	$1,154,589
Transformers	$10,044,235	$3,145,884	$1,356,466	$4,000,188	$897,014	$589,944	$54,739
Streetlights							
Customer Costs	$47,392,116	$41,312,469	$4,243,113	$710,489	$886,389	$239,657	
Network	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Energy	$54,281,863	$3,430,739	$5,505,773	$20,264,704	$25,080,647		
Distribution							
ISA Transmission	$7,480,888	$558,036	$914,980	$2,688,986	$3,318,886		
Stations	$7,395,709	$551,682	$904,562	$2,658,368	$3,281,096		
Wires & Related Equip.	$96,953,611	$9,055,285	$11,785,257	$33,674,602	$42,438,468		
Transformers	$8,186,229	$538,008	$859,462	$4,176,244	$2,612,514		
Streetlights							
Customer Costs	$3,507,652	$2,402,765	$394,355	$141,196	$569,336		

Table 3.65: 2017 Allocation Factors

Non-network	Total	Residential	Small	Medium	Large	High Demand	Lights
Energy	85.53%	32.17%	11.28%	20.27%	9.82%	11.38%	0.60%
Distribution							
ISA Transmission	86.15%	36.96%	12.80%	18.63%	8.88%	8.45%	0.43%
Stations	85.05%	36.49%	12.64%	18.39%	8.77%	8.34%	0.43%
Wires & Related Equip.	100.00%	48.51%	14.15%	19.15%	9.12%	8.62%	0.44%
Transformers	100.00%	31.47%	13.47%	39.73%	8.91%	5.85%	0.57%
Streetlights							100.00%
Customer Costs	93.13%	81.22%	8.30%	1.39%	1.74%	0.47%	
Utility Discount Program	80.37%	36.89%	10.85%	16.36%	7.80%	8.06%	0.42%
Network	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Energy	14.47%	0.93%	1.47%	5.40%	6.68%		
Distribution							
ISA Transmission	13.85%	1.03%	1.69%	4.98%	6.14%		
Stations	14.95%	1.11%	1.83%	5.37%	6.63%		
Wires & Related Equip.	100.00%	9.34%	12.16%	34.74%	43.76%		
Transformers	100.00%	6.62%	10.50%	50.99%	31.89%		
Streetlights							
Customer Costs	6.87%	4.72%	0.77%	0.28%	1.10%		
Utility Discount Program	19.63%	1.86%	2.26%	7.01%	8.50%		

Table 3.66: 2018 Allocation Factors

Non-network	Total	Residential	Small	Medium	Large	High Demand	Lights
Energy	85.47%	31.87%	11.28%	20.36%	9.88%	11.50%	0.58%
Distribution							
ISA Transmission	86.15%	36.97%	12.80%	18.63%	8.88%	8.45%	0.41%
Stations	85.05%	36.50%	12.64%	18.40%	8.77%	8.34%	0.41%
Wires & Related Equip.	100.00%	48.52%	14.16%	19.15%	9.12%	8.63%	0.42%
Transformers	100.00%	31.32%	13.50%	39.83%	8.93%	5.87%	0.54%
Streetlights							100.00%
Customer Costs	93.11%	81.16%	8.34%	1.40%	1.74%	0.47%	0.00%
Utility Discount Program	80.67%	36.46%	10.88%	16.65%	7.95%	8.32%	0.41%
Network	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Energy	14.53%	0.92%	1.47%	5.42%	6.71%		
Distribution							
ISA Transmission	13.85%	1.03%	1.69%	4.98%	6.15%		
Stations	14.95%	1.12%	1.83%	5.37%	6.63%		
Wires & Related Equip.	100.00%	9.34%	12.16%	34.73%	43.77%		
Transformers	100.00%	6.57%	10.50%	51.02%	31.91%		
Streetlights							
Customer Costs	6.89%	4.72%	0.77%	0.28%	1.12%		
Utility Discount Program	19.33%	1.79%	2.21%	6.91%	8.40%		

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 2017 and 2018, 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 85% (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 2017 and 2018 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 and Lake Forest Park are similarly grouped together. Tukwila has a unique franchise agreement and is 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 2017 and 2018 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 the last rate case, all jurisdictions were broken out separately, revenue requirements were determined for each rate class and rates were calculated separately for each jurisdiction. In this rate case there is a small technical change in the process: revenue requirements are calculated by customer class net of franchise payments. The separation of energy consumption by franchise payment groups (Shoreline & SeaTac, Burien & Lake Forest Park, and Tukwila) 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: 2017 Initial Allocation of Functionalized Revenue Requirements

Non-network	Total	Residential	Small	Medium	Large	High Demand	Lights
Total Energy	**$482,513,339**	**$181,511,532**	**$63,636,646**	**$114,342,829**	**$55,424,487**	**$64,185,155**	**$3,412,688**
Production	$111,592,243	$41,978,692	$14,717,430	$26,444,394	$12,818,180	$14,844,285	$789,262
Purchased Power	$269,879,048	$101,522,913	$35,593,208	$63,954,157	$30,999,988	$35,900,000	$1,908,783
Conservation	$46,150,803	$17,360,977	$6,086,634	$10,936,513	$5,301,169	$6,139,098	$326,412
Transmission-Long Distance	$54,891,245	$20,648,950	$7,239,374	$13,007,765	$6,305,150	$7,301,773	$388,231
Total Retail Services	**$299,003,571**	**$164,570,847**	**$36,615,621**	**$45,330,664**	**$21,077,587**	**$18,711,345**	**$12,697,506**
Distribution	$202,089,090	$86,912,330	$27,215,022	$40,750,836	$17,961,557	$16,638,983	$12,610,361
ISA Transmission	$14,418,389	$6,186,112	$2,142,563	$3,117,994	$1,485,954	$1,413,459	$72,307
Stations	$38,504,761	$16,520,206	$5,721,782	$8,326,702	$3,968,287	$3,774,686	$193,098
Wires & Related Equip.	$122,927,553	$59,637,746	$17,395,041	$23,539,867	$11,214,509	$10,601,790	$538,600
Transformers	$14,515,094	$4,568,266	$1,955,635	$5,766,273	$1,292,807	$849,049	$83,064
Streetlights	$11,723,292						$11,723,292
Customer Costs	$80,294,964	$70,030,674	$7,157,737	$1,197,666	$1,502,618	$406,269	
Utility Discount Program	$16,619,517	$7,627,843	$2,242,862	$3,382,162	$1,613,412	$1,666,093	$87,145
Total	**$781,516,910**	**$346,082,379**	**$100,252,268**	**$159,673,494**	**$76,502,074**	**$82,896,501**	**$16,110,195**
Network	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Total Energy	**$81,661,331**	**$5,228,472**	**$8,308,465**	**$30,460,290**	**$37,664,104**		
Production	$18,886,050	$1,209,204	$1,921,523	$7,044,639	$8,710,685		
Purchased Power	$45,674,763	$2,924,386	$4,647,085	$17,037,029	$21,066,262		
Conservation	$7,810,636	$500,086	$794,677	$2,913,426	$3,602,447		
Transmission-Long Distance	$9,289,882	$594,797	$945,180	$3,465,196	$4,284,710		
Total Retail Services	**$65,360,105**	**$9,170,261**	**$7,694,896**	**$22,758,826**	**$25,736,122**		
Distribution	$55,374,482	$4,712,73	$6,561,909	$21,071,745	$23,028,089		
ISA Transmission	$2,318,191	$172,925	$283,536	$833,268	$1,028,462		
Stations	$6,766,150	$504,721	$827,561	$2,432,075	$3,001,793		
Wires & Related Equip.	$35,673,264	$3,332,500	$4,336,487	$12,392,543	$15,611,734		
Transformers	$10,616,877	$702,593	$1,114,325	$5,413,859	$3,386,099		
Streetlights	$0						
Customer Costs	$5,925,750	$4,073,199	$665,178	$238,049	$949,325		
Utility Discount Program	$4,059,872	$384,323	$467,809	$1,449,032	$1,758,708		
Total	**$147,021,435**	**$14,398,733**	**$16,003,361**	**$53,219,116**	**$63,400,226**		
Total Service Territory	**$928,538,345**	**$360,481,112**	**$116,255,629**	**$212,892,609**	**$139,902,300**	**$82,896,501**	**$16,110,195**

Table 4.2: 2018 Initial Allocation of Functionalized Revenue Requirements

Non-network	Total	Residential	Small	Medium	Large	High Demand	Lights
Total Energy	**$502,294,069**	**$187,316,556**	**$66,317,128**	**$119,636,363**	**$58,049,211**	**$67,590,262**	**$3,384,549**
Production	$120,730,628	$45,023,119	$15,939,883	$28,755,612	$13,952,619	$16,245,891	$813,505
Purchased Power	$275,104,080	$102,592,390	$36,321,577	$65,524,269	$31,793,278	$37,018,866	$1,853,701
Conservation	$49,295,636	$18,383,432	$6,508,428	$11,741,231	$5,697,007	$6,633,375	$332,163
Transmission-Long Distance	$57,163,725	$21,317,616	$7,547,240	$13,615,252	$6,606,308	$7,692,130	$385,180
Total Retail Services	**$321,485,770**	**$176,252,606**	**$39,472,186**	**$49,064,856**	**$22,776,891**	**$20,264,061**	**$13,655,170**
Distribution	$218,524,337	$94,008,926	$29,442,945	$44,098,384	$19,421,961	$17,988,615	$13,563,506
ISA Transmission	$15,467,406	$6,637,608	$2,298,939	$3,345,563	$1,594,407	$1,516,621	$74,268
Stations	$40,947,686	$17,572,094	$6,086,104	$8,856,886	$4,220,959	$4,015,030	$196,612
Wires & Related Equip.	$133,652,002	$64,847,041	$18,922,582	$25,598,925	$12,194,535	$11,528,287	$560,632
Transformers	$15,811,419	$4,952,183	$2,135,320	$6,297,010	$1,412,060	$928,678	$86,170
Streetlights	$12,645,824						$12,645,824
Customer Costs	$85,074,038	$74,160,405	$7,616,852	$1,275,405	$1,591,165	$430,210	
Utility Discount Program	$17,887,395	$8,083,274	$2,412,388	$3,691,067	$1,763,765	$1,845,236	$91,664
Total	**$823,779,838**	**$363,569,162**	**$105,789,314**	**$168,701,219**	**$80,826,102**	**$87,854,323**	**$17,039,719**
Network	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Total Energy	**$81,661,331**	**$5,228,472**	**$8,308,465**	**$30,460,290**	**$37,664,104**		
Production	$18,886,050	$1,209,204	$1,921,523	$7,044,639	$8,710,685		
Purchased Power	$45,674,763	$2,924,386	$4,647,085	$17,037,029	$21,066,262		
Conservation	$7,810,636	$500,086	$794,677	$2,913,426	$3,602,447		
Transmission-Long Distance	$9,289,882	$594,797	$945,180	$3,465,196	$4,284,710		
Total Retail Services	**$65,360,105**	**$9,170,261**	**$7,694,896**	**$22,758,826**	**$25,736,122**		
Distribution	$55,374,482	$4,712,739	$6,561,909	$21,071,745	$23,028,089		
ISA Transmission	$2,318,191	$172,925	$283,536	$833,268	$1,028,462		
Stations	$6,766,150	$504,721	$827,561	$2,432,075	$3,001,793		
Wires & Related Equip.	$35,673,264	$3,332,500	$4,336,487	$12,392,543	$15,611,734		
Transformers	$10,616,877	$702,593	$1,114,325	$5,413,859	$3,386,099		
Streetlights	$0						
Customer Costs	$5,925,750	$4,073,199	$665,178	$238,049	$949,325		
Utility Discount Program	$4,059,872	$384,323	$467,809	$1,449,032	$1,758,708		
Total	**$147,021,435**	**$14,398,733**	**$16,003,361**	**$53,219,116**	**$63,400,226**		
Total Service Territory	**$928,538,345**	**$360,481,112**	**$116,255,629**	**$212,892,609**	**$139,902,300**	**$82,896,501**	**$16,110,195**

Table 4.3: Percentage of Energy Consumption by Franchise Group 2017-2018

2017	Total	Residential	Small	Medium	Large	High Demand
Non-network kWh						
City of Seattle	6,797,601	2,487,147	928,568	1,667,795	775,894	879,014
Shoreline and SeaTac	407,173	245,224	49,133	79,154	33,661	
Tukwila	504,422	58,039	28,090	102,633	109,155	206,505
Burien and Lake Forest Park	359,028	239,901	54,567	54,844	9,716	
Percentage						
City of Seattle	84.25%	82.08%	87.57%	87.57%	83.57%	80.98%
Shoreline and SeaTac	5.05%	8.09%	4.63%	4.16%	3.63%	
Tukwila	6.25%	1.92%	2.65%	5.39%	11.76%	19.02%
Burien and Lake Forest Park	4.45%	7.92%	5.15%	2.88%	1.05%	
2018	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**
Non-network kWh						
City of Seattle	6,812,305	2,481,483	933,154	1,676,279	779,985	884,897
Shoreline and SeaTac	407,437	244,666	49,376	79,557	33,839	0
Tukwila	506,908	57,906	28,228	103,155	109,731	207,887
Burien and Lake Forest Park	359,081	239,355	54,837	55,123	9,767	0
Percentage						
City of Seattle	84.25%	82.08%	87.57%	87.57%	83.57%	80.98%
Shoreline and SeaTac	5.04%	8.09%	4.63%	4.16%	3.63%	
Tukwila	6.27%	1.92%	2.65%	5.39%	11.76%	19.02%
Burien and Lake Forest Park	4.44%	7.92%	5.15%	2.88%	1.05%	

Table 4.4:
2017 and 2018 Total Non-network Revenue Requirements Allocated by Jurisdiction

2017	Total	Residential	Small	Medium	Large	High Demand
Total Non-network	**$781,516,91**	**$346,082,37**	**$100,252,26**	**$159,673,49**	**$76,502,07**	**$82,896,501**
City of Seattle	$658,845,19	$284,049,29	$87,792,094	$139,833,555	$63,933,46	$67,126,592
Shoreline and SeaTac	$42,061,851	$28,006,292	$4,645,337	$6,636,559	$2,773,663	
Tukwila Energy	$30,050,971	$3,476,430	$1,685,784	$6,162,138	$6,516,283	$12,210,335
Tukwila Retail Services	$12,602,573	$3,151,971	$969,976	$2,442,950	$2,478,102	$3,559,574
Burien & Lake Forest	$37,956,322	$27,398,388	$5,159,076	$4,598,292	$800,566	
2018	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**
Total Non-network	**$823,779,83**	**$363,569,16**	**$105,789,31**	**$168,701,21**	**$80,826,10**	**$87,854,323**
City of Seattle	$694,510,25	$298,401,68	$92,640,951	$147,739,557	$67,547,08	$71,141,257
Shoreline and SeaTac	$44,265,509	$29,421,389	$4,901,904	$7,011,781	$2,930,435	
Tukwila Energy	$31,474,803	$3,587,612	$1,756,792	$6,447,416	$6,824,873	$12,858,109
Tukwila Retail Services	$13,598,395	$3,375,708	$1,045,649	$2,644,192	$2,677,890	$3,854,956
Burien & Lake Forest	$39,930,874	$28,782,769	$5,444,017	$4,858,273	$845,815	

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 2017-2022 Strategic Plan Update, assumed net wholesale revenues (NWR) in 2017 and 2018 are forecast to be $60 million. **Tables 4.5** and **4.6** show how this net wholesale revenue credit is allocated among customers in 2017 and 2018, 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: 2017 Net Wholesale Credit Allocation

Revenue Requirements	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
City of Seattle	$658,845,194	$284,049,298	$87,792,094	$139,833,555	$63,933,460	$67,126,592	$16,110,195
Shoreline and SeaTac	$42,061,851	$28,006,292	$4,645,337	$6,636,559	$2,773,663	$0	$0
Tukwila	$42,653,543	$6,628,401	$2,655,761	$8,605,088	$8,994,385	$15,769,909	$0
Burien and Lake Forest Park	$37,956,322	$27,398,388	$5,159,076	$4,598,292	$800,566	$0	$0
Network	$147,021,435	$14,398,733	$16,003,361	$53,219,116	$63,400,226	$0	$0
Total Service Territory	**$928,538,345**	**$360,481,112**	**$116,255,629**	**$212,892,609**	**$139,902,300**	**$82,896,501**	**$16,110,195**
% of Total Service Territory Revenue Requirements	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
City of Seattle	70.96%	30.59%	9.45%	15.06%	6.89%	7.23%	1.74%
Shoreline and SeaTac	4.53%	3.02%	0.50%	0.71%	0.30%	0.00%	0.00%
Tukwila	4.59%	0.71%	0.29%	0.93%	0.97%	1.70%	0.00%
Burien and Lake Forest Park	4.09%	2.95%	0.56%	0.50%	0.09%	0.00%	0.00%
Network	15.83%	1.55%	1.72%	5.73%	6.83%	0.00%	0.00%
Total Service Territory	100.00%	38.82%	12.52%	22.93%	15.07%	8.93%	1.74%
NWR Credit	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
City of Seattle	$42,573,054	$18,354,609	$5,672,922	$9,035,721	$4,131,232	$4,337,565	$1,041,004
Shoreline and SeaTac	$2,717,940	$1,809,702	$300,171	$428,839	$179,228	$0	$0
Tukwila	$2,756,173	$428,312	$171,609	$556,041	$581,196	$1,019,015	$0
Burien and Lake Forest Park	$2,452,650	$1,770,421	$333,368	$297,131	$51,731	$0	$0
Network	$9,500,185	$930,413	$1,034,100	$3,438,896	$4,096,776	$0	$0
Total	**$60,000,002**	**$23,293,456**	**$7,512,170**	**$13,756,628**	**$9,040,163**	**$5,356,580**	**$1,041,004**

Table 4.6: 2018 Net Wholesale Credit Allocation

Revenue Requirements	Total	Residential	Small	Medium	Large	High Demand	Lights
City of Seattle	$694,510,258	$298,401,686	$92,640,951	$147,739,557	$67,547,089	$71,141,257	$17,039,719
Shoreline and SeaTac	$44,265,509	$29,421,389	$4,901,904	$7,011,781	$2,930,435	$0	$0
Tukwila	$45,073,198	$6,963,319	$2,802,441	$9,091,608	$9,502,763	$16,713,066	$0
Burien and Lake Forest Park	$39,930,874	$28,782,769	$5,444,017	$4,858,273	$845,815	$0	$0
Network	$155,995,405	$15,214,625	$16,972,260	$56,498,065	$67,310,455	$0	$0
Total Service Territory	**$979,775,243**	**$378,783,788**	**$122,761,573**	**$225,199,284**	**$148,136,557**	**$87,854,323**	**$17,039,719**
% of Total Service Territory Revenue Requirements	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
City of Seattle	70.88%	30.46%	9.46%	15.08%	6.89%	7.26%	1.74%
Shoreline and SeaTac	4.52%	3.00%	0.50%	0.72%	0.30%	0.00%	0.00%
Tukwila	4.60%	0.71%	0.29%	0.93%	0.97%	1.71%	0.00%
Burien and Lake Forest Park	4.08%	2.94%	0.56%	0.50%	0.09%	0.00%	0.00%
Network	15.92%	1.55%	1.73%	5.77%	6.87%	0.00%	0.00%
Total Service Territory	100.00%	38.66%	12.53%	22.98%	15.12%	8.97%	1.74%
NWR Credit	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
City of Seattle	$42,530,792	$18,273,683	$5,673,196	$9,047,354	$4,136,485	$4,356,586	$1,043,487
Shoreline and SeaTac	$2,710,755	$1,801,723	$300,185	$429,391	$179,456	$0	$0
Tukwila	$2,760,217	$426,423	$171,617	$556,757	$581,935	$1,023,484	$0
Burien and Lake Forest Park	$2,445,308	$1,762,615	$333,384	$297,514	$51,796	$0	$0
Network	$9,552,930	$931,721	$1,039,356	$3,459,859	$4,121,994	$0	$0
Total	**$60,000,002**	**$23,196,165**	**$7,517,739**	**$13,790,875**	**$9,071,666**	**$5,380,070**	**$1,043,487**

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. This is a small technical change from the 2015-2016 Rate Case where non-franchise suburban customers were treated in the same manner as franchise 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%. 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 distribution is based on energy and distribution revenue requirements as a percent of total revenue requirements before the NWR credit. Revenues from these rate differential 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 2017 and 2018.

Table 4.7: 2017 Franchise Adjustments

Shoreline and SeaTac	Total	Residential	Small	Medium	Large	High Demand
Retail Revenue	$39,343,911	$26,196,590	$4,345,166	$6,207,720	$2,594,435	$0
Differential (8%)	$3,147,513	$2,095,727	$347,613	$496,618	$207,555	$0
Total Adjustment	**$3,147,513**	**$2,095,727**	**$347,613**	**$496,618**	**$207,555**	**$0**
Tukwila	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**
Total Energy	$30,050,971	$3,476,430	$1,685,784	$6,162,138	$6,516,283	$12,210,335
Total Distribution	$12,602,573	$3,151,971	$969,976	$2,442,950	$2,478,102	$3,559,574
Energy Differential (8%)	$2,404,078	$278,114	$134,863	$492,971	$521,303	$976,827
Retail Services Differential (6%)	$756,154	$189,118	$58,199	$146,577	$148,686	$213,574
Total Adjustment	**$3,160,232**	**$467,233**	**$193,061**	**$639,548**	**$669,989**	**$1,190,401**
Burien and Lake Forest Park	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**
Retail Revenue	$35,503,672	$25,627,968	$4,825,708	$4,301,161	$748,835	$0
Differential (6%)	$2,130,220	$1,537,678	$289,542	$258,070	$44,930	$0
Total Adjustment	**$2,130,220**	**$1,537,678**	**$289,542**	**$258,070**	**$44,930**	**$0**
Total Franchise Adjustments	**$8,437,965**	**$4,100,638**	**$830,217**	**$1,394,235**	**$922,474**	**$1,190,401**

Table 4.8: 2018 Franchise Adjustments

Shoreline and SeaTac	Total	Residential	Small	Medium	Large	High Demand
Retail Revenue	$41,554,754	$27,619,666	$4,601,719	$6,582,390	$2,750,979	$0
Differential (8%)	$3,324,380	$2,209,573	$368,137	$526,591	$220,078	$0
Total Adjustment	**$3,324,380**	**$2,209,573**	**$368,137**	**$526,591**	**$220,078**	**$0**
Tukwila	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**
Total Energy	$31,474,803	$3,587,612	$1,756,792	$6,447,416	$6,824,873	$12,858,109
Total Distribution	$13,598,395	$3,375,708	$1,045,649	$2,644,192	$2,677,890	$3,854,956
Energy Differential (8%)	$2,517,984	$287,009	$140,543	$515,793	$545,990	$1,028,649
Retail Services Differential (6%)	$815,904	$202,542	$62,739	$158,652	$160,673	$231,297
Total Adjustment	**$3,333,888**	**$489,551**	**$203,282**	**$674,445**	**$706,663**	**$1,259,946**
Burien and Lake Forest Park	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**
Retail Revenue	$37,485,566	$27,020,154	$5,110,634	$4,560,759	$794,019	$0
Differential (6%)	$2,249,134	$1,621,209	$306,638	$273,646	$47,641	$0
Total Adjustment	**$2,249,134**	**$1,621,209**	**$306,638**	**$273,646**	**$47,641**	**$0**
Total Franchise Adjustment	**$8,907,402**	**$4,320,334**	**$878,058**	**$1,474,682**	**$974,383**	**$1,259,946**

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 2017 and 2018 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: 2017 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	**$148,976,736**	**$55,727,363**	**$5,228,472**	**$8,308,465**	**$154,205,208**	**$64,035,828**
Production	$34,454,277	$12,888,227	$1,209,204	$1,921,523	$35,663,481	$14,809,749
Purchased Power	$83,325,572	$31,169,392	$2,924,386	$4,647,085	$86,249,957	$35,816,478
Conservation	$14,249,131	$5,330,138	$500,086	$794,677	$14,749,217	$6,124,815
Transmission-Long Distance	$16,947,756	$6,339,606	$594,797	$945,180	$17,542,553	$7,284,786
Total Retail Services	**$135,072,562**	**$32,064,732**	**$9,170,261**	**$7,694,896**	**$144,242,823**	**$39,759,628**
Distribution	$71,333,844	$23,832,516	$4,712,739	$6,561,909	$76,046,583	$30,394,425
ISA Transmission	$5,077,291	$1,876,268	$172,925	$283,536	$5,250,216	$2,159,803
Stations	$13,559,064	$5,010,632	$504,721	$827,561	$14,063,784	$5,838,193
Wires & Related Equip.	$48,948,057	$15,233,043	$3,332,500	$4,336,487	$52,280,557	$19,569,530
Transformers	$3,749,433	$1,712,573	$702,593	$1,114,325	$4,452,026	$2,826,898
Streetlights	$0	$0	$0	$0	$0	$0
Customer Costs	$57,478,117	$6,268,115	$4,073,199	$665,178	$61,551,316	$6,933,293
Low-Income Assistance	$6,260,600	$1,964,101	$384,323	$467,809	$6,644,924	$2,431,910
Subtotal	**$284,049,298**	**$87,792,094**	**$14,398,733**	**$16,003,361**	**$298,448,031**	**$103,795,455**
NWR Credit	-$18,354,609	-$5,672,922	-$930,413	-$1,034,100	-$19,285,022	-$6,707,022
Franchise Adjustment					-$8,437,965	
Total	**$265,694,689**	**$82,119,172**	**$13,468,320**	**$14,969,261**	**$270,725,044**	**$97,088,433**

Table 4.10: 2018 City of Seattle Residential and Small General Service Revenue Requirements

City of Seattle	Non-network		Network		Total	
	Residential	Small	Residential	Small	Residential	Small
Total Energy	**$153,741,246**	**$58,074,692**	**$5,395,687**	**$8,658,432**	**$159,136,933**	**$66,733,123**
Production	$36,953,009	$13,958,743	$1,296,899	$2,081,127	$38,249,908	$16,039,871
Purchased Power	$84,203,352	$31,807,233	$2,955,192	$4,742,182	$87,158,544	$36,549,415
Conservation	$15,088,318	$5,699,508	$529,538	$849,747	$15,617,856	$6,549,255
Transmission-Long Distance	$17,496,568	$6,609,207	$614,058	$985,375	$18,110,626	$7,594,583
Total Retail Services	**$144,660,439**	**$34,566,259**	**$9,818,939**	**$8,313,828**	**$154,479,378**	**$42,880,087**
Distribution	$77,158,420	$25,783,534	$5,107,844	$7,115,441	$82,266,264	$32,898,975
ISA Transmission	$5,447,859	$2,013,208	$185,568	$304,265	$5,633,427	$2,317,473
Stations	$14,422,407	$5,329,673	$536,919	$880,355	$14,959,326	$6,210,029
Wires & Related Equip.	$53,223,618	$16,570,728	$3,630,746	$4,725,337	$56,854,364	$21,296,065
Transformers	$4,064,535	$1,869,925	$754,612	$1,205,484	$4,819,147	$3,075,409
Streetlights	$0	$0	$0	$0	$0	$0
Customer Costs	$60,867,621	$6,670,168	$4,313,226	$707,911	$65,180,847	$7,378,078
Low-Income Assistance	$6,634,398	$2,112,557	$397,869	$490,477	$7,032,267	$2,603,034
Subtotal	**$298,401,686**	**$92,640,951**	**$15,214,625**	**$16,972,260**	**$313,616,311**	**$109,613,211**
NWR Credit	-$18,273,683	-$5,673,196	-$931,721	-$1,039,356	-$19,205,404	-$6,712,553
Franchise Adjustment					-$8,907,402	
Total	**$280,128,003**	**$86,967,755**	**$14,282,904**	**$15,932,903**	**$285,503,505**	**$102,900,658**

4.3 Final Allocation

Tables 4.11 and **4.12** summarize the final allocation of the 2017 and 2018 revenue requirements for City, Network and Franchise Cities.

Table 4.11: Final Allocation of 2017 Revenue Requirements

Total Service Territory	Total	Residential	Small	Medium	Large	High Demand	Lights
Total Energy	$564,174,670	$186,740,004	$71,945,112	$144,803,119	$93,088,591	$64,185,155	$3,412,688
Total Retail Services	$364,363,675	$173,741,108	$44,310,517	$68,089,490	$46,813,708	$18,711,345	$12,697,506
Subtotal	$928,538,345	$360,481,112	$116,255,629	$212,892,609	$139,902,300	$82,896,501	$16,110,195
NWR Credit	-$60,000,002	-$23,293,456	-$7,512,170	-$13,756,628	-$9,040,163	-$5,356,580	-$1,041,004
Franchise Adjustment	$0	-$4,337,327	$830,217	$1,394,235	$922,474	$1,190,401	$0
Total	**$868,538,343**	**$332,850,329**	**$109,573,676**	**$200,530,216**	**$131,784,610**	**$78,730,322**	**$15,069,191**
Load (MWh)	9,432,200	3,117,600	1,198,799	2,411,755	1,559,344	1,085,520	59,183
Average Rate ($/MWh)	**$92.08**	**$106.76**	**$91.40**	**$83.15**	**$84.51**	**$72.53**	**$254.62**
City of Seattle	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Total Energy	$420,082,649	$154,205,208	$64,035,828	$100,135,370	$46,318,735	$51,974,820	$3,412,688
Total Retail Services	$269,164,640	$144,242,823	$39,759,628	$39,698,185	$17,614,726	$15,151,771	$12,697,506
Subtotal	$689,247,288	$298,448,031	$103,795,455	$139,833,555	$63,933,460	$67,126,592	$16,110,195
NWR Credit	-$44,537,567	-$19,285,022	-$6,707,022	-$9,035,721	-$4,131,232	-$4,337,565	-$1,041,004
Franchise Adjustment	-$8,437,965	-$8,437,965					
Total	**$636,271,756**	**$270,725,044**	**$97,088,433**	**$130,797,834**	**$59,802,228**	**$62,789,026**	**$15,069,191**
Load (MWh)	7,023,331	2,574,436	1,067,009	1,667,795	775,894	879,014	59,183
Average Rate ($/MWh)	**$90.59**	**$105.16**	**$90.99**	**$78.43**	**$77.08**	**$71.43**	**$254.62**
Network	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Total Energy	$68,124,394			$30,460,290	$37,664,104		
Total Retail Services	$48,494,948			$22,758,826	$25,736,122		
Subtotal	$116,619,341			$53,219,116	$63,400,226		
NWR Credit	-$7,535,672			-$3,438,896	-$4,096,776		
Franchise Adjustment							
Total	**$109,083,669**			**$49,780,219**	**$59,303,450**		
Load (MWh)	1,138,247			507,328	630,918		
Average Rate ($/MWh)	**$95.83**			**$98.12**	**$94.00**		
Franchise Cities	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Total Energy	$75,967,627	$32,534,796	$7,909,284	$14,207,460	$9,105,753	$12,210,335	
Total Retail Services	$46,704,088	$29,498,285	$4,550,889	$5,632,479	$3,462,861	$3,559,574	
Subtotal	$122,671,716	$62,033,081	$12,460,173	$19,839,938	$12,568,614	$15,769,909	
NWR Credit	-$7,926,763	-$4,008,434	-$805,148	-$1,282,011	-$812,155	-$1,019,015	
Franchise Adjustment	$8,437,965	$4,100,638	$830,217	$1,394,235	$922,474	$1,190,401	
Total	**$123,182,918**	**$62,125,285**	**$12,485,243**	**$19,952,163**	**$12,678,933**	**$15,941,295**	
Load (MWh)	1,270,622	543,164	131,790	236,631	152,532	206,505	
Average Rate ($/MWh)	**$96.95**	**$114.38**	**$94.74**	**$84.32**	**$83.12**	**$77.20**	

Table 4.12: Final Allocation of 2018 Revenue Requirements

Total Service Territory	Total	Residential	Small	Medium	Large	High Demand	Lights
Total Energy	$587,666,398	$192,712,243	$74,975,559	$151,506,821	$97,496,964	$67,590,262	$3,384,549
Total Retail Services	$392,108,845	$186,071,545	$47,786,014	$73,692,463	$50,639,593	$20,264,061	$13,655,170
Subtotal	$979,775,243	$378,783,788	$122,761,573	$225,199,284	$148,136,557	$87,854,323	$17,039,719
NWR Credit	-$60,000,002	-$23,196,165	-$7,517,739	-$13,790,875	-$9,071,666	-$5,380,070	-$1,043,487
Franchise Adjustment	$0	-$4,587,068	$878,058	$1,474,682	$974,383	$1,259,946	$0
Total	**$919,775,241**	**$351,000,554**	**$116,121,892**	**$212,883,091**	**$140,039,274**	**$83,734,199**	**$15,996,231**
Load (MWh)	9,456,100	3,110,500	1,204,720	2,424,023	1,567,566	1,092,785	56,507
Average Rate ($/MWh)	**$97.27**	**$112.84**	**$96.39**	**$87.82**	**$89.34**	**$76.62**	**$283.09**
City of Seattle	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Total Energy	$437,270,162	$159,136,933	$66,733,123	$104,771,165	$48,512,239	$54,732,152	$3,384,549
Total Retail Services	$289,426,981	$154,479,378	$42,880,087	$42,968,392	$19,034,849	$16,409,105	$13,655,170
Subtotal	$726,697,143	$313,616,311	$109,613,211	$147,739,557	$67,547,089	$71,141,257	$17,039,719
NWR Credit	-$44,501,870	-$19,205,404	-$6,712,553	-$9,047,354	-$4,136,485	-$4,356,586	-$1,043,487
Franchise Adjustment	-$8,907,402	-$8,907,402					
Total	**$673,287,871**	**$285,503,505**	**$102,900,658**	**$138,692,203**	**$63,410,604**	**$66,784,670**	**$15,996,231**
Load (MWh)	7,038,520	2,568,573	1,072,279	1,676,279	779,985	884,897	56,507
Average Rate ($/MWh)	**$95.66**	**$111.15**	**$95.96**	**$82.74**	**$81.30**	**$75.47**	**$283.09**
Network	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Total Energy	$71,318,211			$31,870,458	$39,447,753		
Total Retail Services	$52,490,309			$24,627,607	$27,862,702		
Subtotal	$123,808,520			$56,498,065	$67,310,455		
NWR Credit	-$7,581,853			-$3,459,859	-$4,121,994		
Franchise Adjustment	$0						
Total	**$116,226,667**			**$53,038,206**	**$63,188,461**		
Load (MWh)	1,144,154			509,909	634,245		
Average Rate ($/MWh)	**$101.58**			**$104.01**	**$99.63**		
Franchise Cities	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Total Energy	$79,078,025	$33,575,310	$8,242,436	$14,865,198	$9,536,972	$12,858,109	
Total Retail Services	$50,191,556	$31,592,167	$4,905,927	$6,096,464	$3,742,042	$3,854,956	
Subtotal	$129,269,581	$65,167,477	$13,148,363	$20,961,662	$13,279,013	$16,713,066	
NWR Credit	-$7,916,280	-$3,990,761	-$805,186	-$1,283,662	-$813,187	-$1,023,484	
Franchise Adjustment	$8,907,402	$4,320,334	$878,058	$1,474,682	$974,383	$1,259,946	
Total	**$130,260,703**	**$65,497,050**	**$13,221,234**	**$21,152,682**	**$13,440,209**	**$16,949,528**	
Load (MWh)	1,273,426	541,927	132,441	237,835	153,336	207,887	
Average Rate ($/MWh)	**$102.29**	**$120.86**	**$99.83**	**$88.94**	**$87.65**	**$81.53**	

4.4 Average Rate Increases in 2017 and 2018 by Rate Class

Tables 4.13 – 4.15 present the average rates by rate class for 2016-2018. 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 2017 and 2018.

Table 4.13: 2016 Average Rates by Rate Class (Strategic Plan)

	Total	Residential	Small	Medium	Large	High Demand	Lights
All areas	$87.19	$101.64	$85.21	$78.84	$80.57	$67.87	$235.50
City of Seattle	$85.51	$99.95	$84.87	$73.45	$72.95	$66.95	$235.50
Network	$92.30	$0.00	$0.00	$94.55	$90.18	$0.00	$0.00
Franchise Cities	$91.54	$109.49	$87.88	$78.97	$78.85	$71.61	

Table 4.14: 2017 Average Rates by Rate Class

	Total	Residential	Small	Medium	Large	High Demand	Lights
All areas	$92.08	$106.76	$91.40	$83.15	$84.51	$72.53	$254.62
City of Seattle	$90.59	$105.16	$90.99	$78.43	$77.08	$71.43	$254.62
Network	$95.83			$98.12	$94.00		
Franchise Cities	$96.95	$114.38	$94.74	$84.32	$83.12	$77.20	

Table 4.15: 2018 Average Rates by Rate Class

	Total	Residential	Small	Medium	Large	High Demand	Lights
All areas	$97.27	$112.84	$96.39	$87.82	$89.34	$76.62	$283.09
City of Seattle	$95.66	$111.15	$95.96	$82.74	$81.30	$75.47	$283.09
Network	$101.58			$104.01	$99.63		
Franchise Cities	$102.29	$120.86	$99.83	$88.94	$87.65	$81.53	

Table 4.16: 2017 Average Rate Increases by Rate Class

	Total	Residential	Small	Medium	Large	High Demand	Lights
All areas	5.6%	5.0%	7.3%	5.5%	4.9%	6.9%	8.1%
City of Seattle	5.9%	5.2%	7.2%	6.8%	5.7%	6.7%	8.1%
Network	3.8%			3.8%	4.2%		
Franchise Cities	5.9%	4.5%	7.8%	6.8%	5.4%	7.8%	

Table 4.17: 2018 Average Rate Increases by Rate Class

	Total	Residential	Small	Medium	Large	High Demand	Lights
All areas	5.6%	5.7%	5.5%	5.6%	5.7%	5.6%	11.2%
City of Seattle	5.6%	5.7%	5.5%	5.5%	5.5%	5.7%	11.2%
Network	6.0%			6.0%	6.0%		
Franchise Cities	5.5%	5.7%	5.4%	5.5%	5.4%	5.6%	

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.[14]

Assumed Asset Lives and Annualization Factors

Functional Category	Rate Discount	Years of Useful Life	Annualization Factor
In service Area Transmission	0.03	42	0.04219
Substations	0.03	39	0.04384
Non-network Wires and Related Equipment	0.03	32	0.04905
Network Wires and Related Equipment	0.03	32	0.04905
Transformers	0.03	32	0.04905
Meters	0.03	33	0.04816
Service Drops	0.03	33	0.04816

[14] Asset lives are based on 2014 asset depreciation schedules prepared by Seattle City Light's Cost Accounting Unit.

Appendix B

This table illustrates how 2017 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 2017															
			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 4.5)		HD-City Share of RR (E x F)
Energy	Table 3.14	$	35,148,357	$	309,011,176		11.377%	$	564,174,670	$	64,185,155		80.9764%	$	51,974,820
ISA Transmission	Table 3.18	$	4,450,658	$	52,699,662		8.445%	$	16,736,580	$	1,413,459		80.9764%	$	1,144,568
Stations	Table 3.22	$	4,025,836	$	48,283,035		8.338%	$	45,270,911	$	3,774,686		80.9764%	$	3,056,604
Wires and Related Equip. [1]	Table 3.30	$	23,167,669	$	268,628,679		8.624%	$	122,927,553	$	10,601,790		80.9764%	$	8,584,947
Transformers [1]	Table 3.40	$	571,972	$	9,778,264		5.849%	$	14,515,094	$	849,049		80.9764%	$	687,529
Customer Costs	Table 3.62	$	233,911	$	49,641,819		0.471%	$	86,220,717	$	406,270		80.9764%	$	328,983
Utility Discount Program[3]	Table 3.67	$	68,016,960	$	844,220,128		8.057%	$	20,679,389	$	1,666,093		80.9764%	$	1,349,142
Total Rev. Req. before NWR credit														$	67,126,592
Less NWR credit (Table 4.9)[4]															-4,337,565
Total Class 2017 Revenue Requirement														$	62,789,027
2017 Class Load in MWh (Table 4.3)															879,014
Average rate in $/MWh (class rev req / class load)														$	71.4312
Average rate in $/kWh														$	0.0714

(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) Marginal Cost Share for the Utility Discount Program is based on share of total overall 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 4.5 (7.23%)