Adopted
Revenue Requirements Analysis

2013-2014

Seattle City Light
October 2012

Table of Contents

Technical Documentation:

Adopted RRA Financial Report Package.xls
UIPlanner Scenario RRA_2012_Case05

Executive Summary

S.1 Adopted Revenue Requirements

Table S1 shows the Adopted 2013 and 2014 Revenue Requirements and the respective annual changes.

Table S1
Adopted Revenue Requirements

$ Millions	2012 Plan	2013	2014	Difference 2013-2012	Difference 2014-2013
Proposed Revenue Requirement	678.9	711.0	755.9	32.1	44.9

S.2 Drivers of the Increase in Revenue Requirements

The drivers of the **$32.1 million** increase between 2013 and 2012 are:

- $12.1 million lower net wholesale revenue (NWR)
  - 2012 Strategic Plan endorsed moving towards more conservative NWR
- $5.4 million increase to non-power direct O&M
  - Higher labor wages, benefit costs
  - New initiatives (BIPs) such as workforce development, safety, IT maintenance funding restoration, with offset from efficiencies
  - Reductions from shifting labor to capital and other adjustments
- $4.5 million taxes, discounts and uncollectibles (increases with rates)
- $3.8 million increase in net power contract costs
  - Increases in costs for BPA, GCPHA, Stateline Wind
  - Lower revenues from ancillary sales
- $6.3 million other miscellaneous (e.g., lower operating grants, sales of property)

The drivers for the **$44.9 million** change between 2014 and 2013 include:

- $30.2 million higher debt service coverage requirements
  - Higher debt service from 2013 bond issue, while debt service on existing bonds remains flat
- $7.6 million higher power contract costs
  - Higher BPA expenses, added renewables (Columbia Ridge expansion)
- $5.0 million lower planned NWR
  - 2012 Strategic Plan endorsed moving towards more conservative NWR
- $3.1 million higher taxes, discounts and uncollectibles (increases with rates)
- $1.4 million increase to non-power direct O&M
  - Net reduction in new initiatives (with efficiencies); increase due to inflation
- ($2.4) million other miscellaneous (offsetting)

Figure S1 gives a high-level graphical view of the 2013 and 2014 revenue requirement drivers.

Figure S1
High-Level Revenue Requirements Drivers

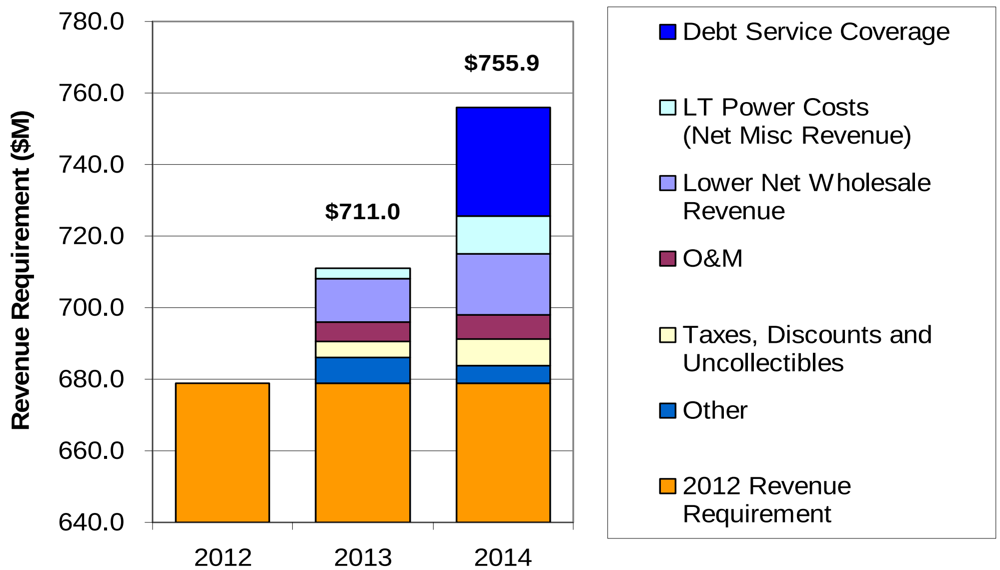


Table S2 provides a summary of the costs and expenses assumed in the adopted revenue requirement. In 2013 the reasons for the revenue requirement increase are comparatively more evenly spread among the categories. However, in 2014 over 85% comes just from three drivers, Debt Service Coverage (67%), Power Costs (17%) and NWR (11%). Each category line is further explained in the individual chapters of the RRA.

Table S2
2013-2014 Revenue Requirement Calculation Summary

Chapter	RRA Category ($ Millions)	2012 Plan	2013	2014	Difference 2013-2012	Difference 2014-2013
1	Debt Service	172.8	172.8	189.6	0.0	16.8
	Debt Service times 1.8	**311.1**	**311.1**	**341.4**	**0.1**	**30.2**
2	**Operating Expenses**					
	Power Contracts	266.1	269.0	276.6	2.9	7.5
	Non-Power O&M	220.5	225.9	227.3	5.4	1.4
	Other Expenses	48.2	52.7	55.8	4.5	3.1
	Total	**534.8**	**547.6**	**559.7**	**12.8**	**12.0**
3	**Operating Revenues**					
	NWR	102.1	90.0	85.0	(12.1)	(5.0)
	Power Revenues	23.9	23.1	23.0	(0.8)	(0.1)
	Other Sources	38.7	36.3	38.4	(2.4)	2.1
	Total	**164.8**	**149.4**	**146.4**	**(15.3)**	**(3.0)**
4	**Revenue Requirements**					
	Proposed	**678.9**	**711.0**	**755.9**	**32.1**	**44.9**
	Target	681.2	709.3	754.6	28.2	45.2
	Difference (Proposed - Target)*	(2.2)	1.7	1.3	3.9	(0.4)

*In many years the target revenue requirement calculated with the adopted revenues and expenses may not equal exactly the adopted revenue requirement. This is because the revenue requirement and the budget are done in parallel, and typically the adopted revenue requirement must be finalized before the budget is. Chapter 4 discusses the difference between the target and adopted revenue requirement in detail.

S.2 Changes in Average Rates

Table S3 displays the changes in average retail rates required to yield the adopted revenue requirement. The adopted average rate increases are **4.4%** in 2013 and **5.6%** in 2014.[1] The section in table S3 shows the retail revenue generated from existing rates, and the nominal increase in retail revenue in 2013 and 2014 resulting from the adopted revenue requirement increases. Average rates for each year are calculated by dividing total retail revenue by the total sales to customers and multiplying by 100 (to get cents/kWh).

Table S3
Changes in Average Rates

	2012 Plan	**2013**	**2014**
Retail Revenue			
Current Rates ($M)	678.9	681.1	686.3
From 2013 Increase ($M)		30.0	30.2
From 2014 Increase ($M)			39.4
Retail Revenue Requirement	**678.9**	**711.0**	**755.9**
Sales to Retail Customers (GWh)	9,631.7	9,654.8	9,746.4
Avg Rates (cents / kWh)			
Current Rates	7.05	7.05	7.04
After 2013 Increase		7.36	7.35
After 2014 Increase			7.76
Annual Rate Increase		4.4%	5.6%

The average rate increase is calculated compared to what the average system rate would be for that year without that years' rate increase (which is not the same as the average rate from the previous year). This method accounts for any changes in projected customer billing determinants between years. Note that an average rate is only a statistic and not actually a customer rate.

The 2013-14 Rate Study is a comprehensive one; therefore, the revenue requirement is only the first of three steps. First the revenue requirement is calculated, then the cost of service and cost allocation study divides the revenue requirement dollars among customer classes, and then finally rate design sets individual rates to collect this revenue. Therefore, the revenue requirement determines that the average rate increase across all customers is 4.4% and 5.6%, but each individual customer class will have a different rate increase that could be lower or higher than the system average.

[1] These average rate increases are consistent with the results of City Lights' Strategic Plan, approved by City Council on 7/2/2012.

Introduction

I.1 Introduction

This report details the 2013 and 2014 revenue requirements developed for City Light's 2013-2014 Rate Study. The revenue requirement is the amount of revenue that City Light must collect from retail customers in a given year to cover operating costs and meet Council-mandated financial policies. Operating revenues, operating costs and capital expenditures (which drive debt service coverage) are determined by the budget, which is developed in conjunction with the revenue requirement. City Light's current rate setting financial policy specifies that rates should be set so that after all operating expenses the remaining net revenue will be equal to 1.8 times debt service.[2] The amount of net revenue available for debt service is also commonly referred to as debt service coverage.

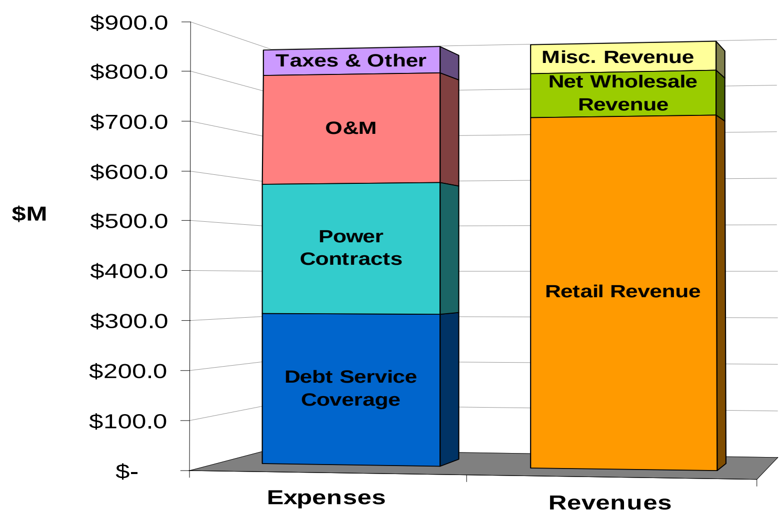
The Revenue Requirements Analysis (RRA) is the first of three reports that make up a full rate study. The other two reports are the Cost of Service and Cost Allocation Report (COSCAR) and the Rate Design Report (RDR). A detailed explanation of the rate-setting process can be found in the document, *Seattle City Light Guide to Rate Making*, posted on City Light's website.

The following equation helps demonstrate the basic derivation of the revenue requirements.

Revenue Requirements = Debt Service * 1.8 + Operating Expenses –Non-Rate Based Revenues

Figure 1 below shows how retail revenue is sized so that total revenues equal total expenses. It also illustrates the relative size of City Light's Revenues and Expenses.

Figure 1
2013 City Light Adopted Revenues and Expenses



The revenue and expenses used in derivation of revenue requirements are consistent with the methodology for calculating debt service coverage for ratemaking. Note that rates use a slightly

[2] City Council Resolution 31187 passed in March 2010.

different definition of operating revenues and expenses than is used in the income statement, because the income statement includes non-cash transactions such as depreciation and mark-to-market valuation for certain energy purchases and sales. These types of transactions are not part of the debt service coverage calculation. City Light's 2011 Annual Financial Report provides information on specific types of adjustments, which are made to the income statement categories.

I.2 RRA Objectives and Organization

The RRA's two main objectives are (1) to summarize how the 2013 and 2014 revenue requirements are determined and (2) to explain what has changed from the revenue requirements used to set the existing 2012 rates. To accomplish this, this report compares the forecast for the adopted 2013 and 2014 revenues and expenses to the forecast that determined the 2012 revenue requirement. Note that 2012 actuals are not used; the *RRA* compares the current proposal to the 2012 plan that was used to set existing rates.

The RRA is organized into 5 chapters with appendices providing additional detail. Chapter 1 explains debt service and debt service coverage. Chapter 2 discusses operating expenses while Chapter 3 discuses non-rate based revenue. The revenue requirement, which is calculated from the values in Chapters 1-3, is summarized in Chapter 4. Finally, Chapter 5 discusses indirect costs and proceeds, such as capital expenses and proceeds from bond issues. These impact the revenue requirements indirectly through their role in size and timing of future debt issues, which ultimately impact future revenue requirements.

Chapter 1: Debt Service and Debt Service Coverage

City Light finances a portion of its capital program by selling municipal power bonds. The bonds are paid back over a term of 20 to 30 years through interest and principal payments, also called debt service. City Light's financial policies require it to set rates sufficient to cover debt service 1.8 times after all required operating expenses are paid. Therefore, changes in debt service have 1.8 times the impact on the revenue requirements that regular expenses have.

For the purpose of the financial forecast and the revenue requirements, federal interest subsidies are subtracted from interest payments instead of treating them as revenue.[3] Table 1.1 shows the debt service projections for the 2012 Plan compared with the forecast for 2013 and 2014 and the year to year changes. There is almost no change in the required debt service coverage in 2013. However, there is a $30.2 million increase in 2014, which is the primary driver for the increase in the 2014 revenue requirement. The reason for the 2014 increase is that debt service on existing debt has very little change while future debt issues create additional debt service.

Table 1.1
Debt Service and Debt Service Coverage

$ Millions	**2012 Plan**	**2013**	**2014**	**Difference 2013-2012**	**Difference 2014-2013**
Debt Service, Gross	176.9	178.3	195.1	1.3	16.8
Federal Subsidies	4.1	5.4	5.4	1.3	0.0
Debt Service, Net of Subsidies	172.8	172.8	189.6	0.0	16.8
Debt Service Coverage (1.8x)	311.1	311.1	341.4	0.1	30.2

City Light anticipates issuing debt in the second quarter of both 2013 and 2014. The details of the planned debt issues are shown in Table 1.2. The size of the planned 2013 debt issue will be the largest new money issue in over a decade. Growth in City Light's capital program necessitates this increased debt; this is discussed further in Chapter 5.

Table 1.2
Planned Debt Issues

	Debt Issue Amount ($M)	Term (years)	Average Rate
2013 Planned Issue	265.0	30	4.5%
2014 Planned Issue	200.0	30	4.5%

Table 1.3 is a breakout of debt service by issue year. The $16.8 million increase in 2014 debt service comes almost entirely from the 2013 planned issue. The reason why there is very little

[3] Federal interest subsidies are subsidies City Light receives on Build America Bonds (BABs), Conservation and Renewable Energy Bonds (CREBs) and Recovery Zone Economic Development Bonds (RZEDs). Traditional accounting treats the subsidies as revenues and uses gross debt service in its debt coverage calculations. With approval from City Light's financial advisors, the financial forecast does not count the subsidies as revenue but rather subtracts the subsidies from debt service and uses net debt service in the debt coverage calculations.

change in existing debt service (through 2012) is mostly due to the adopted payment schedules of City Light's recently refinanced debt. In 2010, 2011 and in 2012 City Light was able to take advantage of low market interest rates and refinanced most of its existing first lien debt. The resulting debt service schedule, which included some front loading of the refinancing savings, has very little change between 2012 and 2014.

Table 1.3
Debt Service by Bond Series[4]

$ Millions	**2012 Plan**	**2013**	**2014**
Debt Service by Bond Series			
2002-2004 Unrefunded Bonds	47.1	31.4	23.6
2008 Bonds	25.5	25.9	26.0
2010 Bond	73.5	78.3	78.3
2011 Bonds	25.8	19.5	26.5
2012 Bonds	5.0	23.3	24.5
Debt Service on Existing Debt	176.9	178.3	178.8
Debt Service on Future Debt			
2013 Bonds	-	-	16.3
2014 Bonds	-	-	-
Total Debt Service	176.9	178.3	195.1
Federal Subsidies	4.1	5.4	5.4
Total Debt Service Net of Subsidies	**172.8**	**172.8**	**189.6**

[4]The debt service payments for many of these bond series reflect refinancing, so the debt service payments on these bonds are not just for the debt issued to cover capital expenses in those years.

Chapter 2: Operating Expenses

2.1 Introduction

Operating expenses are grouped into power contracts expenses, non-power O&M and other expenses. Table 2.1 shows that expenses in all three categories are increasing relative to the 2012 Financial Plan. Each category is discussed in the sections below.

Table 2.1
Operating Expenses

$ Millions	2012 Plan	2013	2014	Difference 2013-2012	Difference 2014-2013
Power Contracts	266.1	269.0	276.6	2.9	7.5
Non-Power O&M	220.5	225.9	227.3	5.4	1.4
Other Expenses	48.2	52.7	55.8	4.5	3.1
Total	**534.8**	**547.6**	**559.7**	**12.8**	**12.0**

2.2 Power Contract Expenses

Power contract expenses include the costs City Light pays to third parties for the acquisition and transmission of energy. In addition, power contact expenses include various payments called water for power that are associated with owning and operating City Light's generating resources. Table 2.2 summarizes planned power contract expenditures for 2013 and 2014 and compares them with the 2012 Financial Plan. A more detailed description of power contracts is located in Appendix A.

Table 2.2
Power Contract Expenses

$ Millions	2012 Plan	2013	2014	Difference 2013-2012	Difference 2014-2013
Long-Term Purchased Power					
BPA	156.5	158.6	162.3	2.1	3.7
Priest Rapids	3.0	3.5	3.3	0.5	-0.2
Grand Coulee	4.0	5.6	5.8	1.6	0.2
High Ross	13.1	13.1	13.1	0.0	0.0
Lucky Peak	6.2	6.5	7.0	0.3	0.5
Stateline Wind Project	25.2	26.8	26.9	1.6	0.1
Small Renewables	9.1	8.0	10.4	-1.0	2.4
Subtotal	**217.1**	**222.1**	**228.9**	**5.0**	**6.7**
Water for Power					
FERC Administrative Fees	2.3	2.3	2.4	0.0	0.0
FERC Land Use Fees	5.7	5.8	5.9	0.1	0.1
WA Dept of Ecology	0.2	0.2	0.2	0.0	0.0
PNCA Storage Fees	1.8	1.8	1.8	0.0	0.0
Subtotal	**9.9**	**10.1**	**10.2**	**0.2**	**0.2**
Wheeling					
BPA Firm Wheeling	36.2	35.6	36.3	-0.5	0.6
South Fork Tolt	0.4	0.4	0.4	0.0	0.0
Grand Coulee	0.2	0.2	0.2	0.0	0.0
Lucky Peak	1.8	0.0	0.0	-1.8	0.0
Columbia Grid and Other	0.6	0.6	0.6	0.0	0.0
Subtotal	**39.2**	**36.8**	**37.5**	**-2.4**	**0.6**
Total Power Contracts	**266.2**	**269.0**	**276.6**	**2.8**	**7.5**

Long-Term Purchased Power Expenses

The forecast of power expenses is based on the power contracts budget; however, there are a few differences between the forecast and the budget. These are discussed in Appendix B. The annual increase in long-term purchased power comes mainly from BPA expenses, Grand Coulee (2013 only), and a growing Renewable Power Program due to the Columbia Ridge Expansion planned to come online in October 2013 (see Appendix A “Small Renewables”).

Water for Power Expenses

Water for power includes various fees and payments associated with owning and operating City Light’s generating resources. City Light is required by law to pay these as a condition of the operation of its dams on the Pend Oreille, Skagit and Tolt rivers. Water for power is not expected to change substantially in 2013 and 2014.

Wheeling Expenses
Wheeling is a term that means transporting power across other entities' power lines. As shown in Table 2.2, wheeling expenses are expected to decrease in 2013 from the 2012 Plan primarily due to the elimination of wheeling costs for Lucky Peak, which will instead be incurred by the buyer of the Lucky Peak output.

2.3 Non-Power Operating and Maintenance Expenses

Non-power operating and maintenance expenses are the costs associated with running the day-to-day operations, excluding purchased power and power-related costs. This is a large and diverse category of costs that include functions such as maintaining and operating the production, distribution and transmission systems, providing customer services such as billing and meter reading, and providing administrative support.

Non-Power O&M Budget
The basis for the non-power O&M in the financial forecast is the Proposed Budget, adjusted to remove costs that do not impact City Light's debt service coverage. (This adjustment is discussed in more detail below.) Table 2.3 shows the non-power O&M in City Light's 2013-2014 Proposed Budget by budget control level (BCL).[5]

Table 2.3
Proposed 2013 and 2014 O&M Budget

$ Millions	2012 Adopted	2013 Proposed	2014 Proposed
Non-Power O&M (includes deferred O&M)			
Conservation Resources and Environmental Affairs	57.8	59.8	61.5
Customer Services	26.8	27.5	28.2
Energy Delivery	70.8	73.8	73.9
Financial Services	29.0	36.2	36.5
General Expenses	77.6	86.2	86.7
Human Resources	6.8	9.4	9.1
Office of Superintendent	2.9	3.1	3.2
Power Supply	62.4	51.0	51.5
Compliance & Security	2.8	3.2	3.4
Total	**336.9**	**350.3**	**354.2**

The annual increases to the Proposed Budget can be explained by three categories:

1. Base Inflation: Increases for labor wages, labor benefits, supplies and all other operating costs.
2. Budget Issue Papers (BIPs): New initiatives and/or policy related changes in funding levels for existing programs.

[5] For more detail see City Light's 2013-2014 Proposed Budget

3. Technical BIPs: Changes that are not policy or new initiative related, such as transfers between BCLs, accounting changes, or City cost allocations.

Table 2.4 breaks down the changes to the O&M budget by the above three categories. Note that the changes are cumulative, so the annual changes for 2014 will be in addition to the annual changes in 2013.

In aggregate, the O&M inflation averages around 3.5% in 2013 and 3.0% in 2014, though each budget cost category was assigned a specific inflation factor. In addition to new and expanded programs, the BIPs include some spending reductions referred to as efficiency savings. The increasing efficiency savings are the primary reason for the negative BIP total in 2014. The negative $8.9 million technical BIP in 2013 is primarily a result of moving the majority of hydro project relicensing costs from deferred O&M to CIP. Appendix B provides a more detailed breakdown of the changes in the 2013 and 2014 proposed O&M budget.

Table 2.4
Summary of Budget Changes

Non-Power O&M Budget ($Millions)		**Annual Changes**				
Budget Year	**Previous Year Adopted**	**Inflation**	**BIPS**	**Technical BIPs**	**Total Change**	**Proposed O&M Budget**
2013	336.9	11.9	10.3	(8.9)	13.3	350.3
2014	350.3	10.5	(4.7)	(1.9)	3.9	354.2

Adjustments from Budget to Financial Forecast
To correspond with City Light's debt service coverage policy, the O&M budget is adjusted to include only costs that will be applied to the debt service coverage calculation. This includes: removing deferred O&M and all projected capitalized and deferred labor loadings, and making a limited number of discretionary budget-to-forecast adjustments. Table 2.5 provides a summary of the budget-to-forecast adjustments and the resulting non-power O&M expenses used in the financial forecast.

Table 2.5
Summary of Budget to Forecast Adjustments

	$ Millions	**2012 Adopted**	**2013 Proposed**	**2014 Proposed**	**Difference 2013-2012**	**Difference 2014-2013**
	Total Non-Power O&M in Budget	**336.9**	**350.3**	**354.2**	**13.3**	**3.9**
less	Deferred O&M in Non-Power O&M Budget	48.5	46.6	47.4	(1.9)	0.8
less	Capital Loadings	65.4	71.7	70.1	6.3	(1.6)
less	Other Adjustments	2.5	6.1	9.5	3.6	3.3
	Total Non-Power O&M for Financial Forecast	**220.5**	**225.9**	**227.3**	**5.4**	**1.4**

The primary reason the O&M in the 2013 financial forecast doesn't change by as much as in the 2013 O&M budget ($13.3 million) is because more labor has been allocated to capital projects on a planning basis relative to 2012. This means there needs to be a larger budget-to-forecast adjustment for capitalized labor loadings. For a more detailed explanation of all budget-to-forecast adjustments see Appendix B.

The resulting $5.4 million and $1.4 million annual increases in the non-power O&M forecast account for roughly 17% and 3% of the total increase in 2013 and 2014 revenue requirements, respectively.

2.4 Other Expenses

Other expenditures include rate discounts, uncollectable accounts, state taxes, other (non-City) taxes and franchise payments. Table 2.6 shows the 2012 Plan compared to the 2013 and 2014 forecasts. Following the table is a short description of each category.

Table 2.6
Other Expenses

$ Millions	**2012 Plan**	**2013**	**2014**	**Difference 2013-2012**	**Difference 2014-2013**
Other Expenses					
Rate Discounts	7.0	9.1	9.6	2.0	0.5
Uncollectable Accounts	6.1	6.4	6.8	0.3	0.4
State Taxes	26.6	27.5	29.2	1.0	1.7
Other (Non-City) Taxes	3.4	4.2	4.3	0.8	0.1
Franchise Payments	5.2	5.5	5.8	0.4	0.3
Total	**48.2**	**52.7**	**55.8**	**4.5**	**3.1**

Rate Discounts
City Light offers low-income residential customers an assisted rate that is 40% of the regular retail rate. The discount given to these customers is modeled as an expense in the forecast, and this expense generally increases as rates increase. The increase in 2013 is a result of a forecasted increase in energy consumption for low-income customers that reflects a gradual increase in consumption over the past few years that was not reflected in the 2012 Plan.

Uncollectable Accounts
Every year, a portion of past-due accounts receivable are never received, despite collection efforts, and must be written off as uncollectable. Uncollectable accounts refer to both retail customers and wholesale counterparties. Uncollectable revenue is projected to remain at around 0.9% of revenue from energy sales to retail customers.

State Taxes
City Light pays a state utility tax on retail revenue and some other sources of outside revenue including Contributions in Aid of Construction (CIAC). It is assumed that 6% of these revenues are not taxable and deducted from the tax base. The remaining revenue is taxed at the State rate of 3.873%.[6] In addition to the state utility tax, City Light pays a state business tax, which amounts to around $0.1 million per year.

Other (Non-City) Taxes
City Light makes payments to some states, counties and school districts where its production facilities are located. The only notable change in these expenses comes from an increase in the contract payment to Pend Oreille County effective 2013, which was specified in a contract signed in 2010.

[6] This tax was increased to 3.8734% effective April 2012, but this slight increase was not incorporated into the rate forecast in order to preserve the base Strategic Plan assumptions. The impact on revenue requirements is trivial.

Payments to Franchise Cities
City Light makes payments to suburban cities with which it has negotiated franchise agreements to construct, operate, replace, and repair the electric and light system to serve those areas.

Chapter 3: Non-Rate Based Revenue

3.1 Introduction

In addition to revenue from retail sales, City Light receives cash from other non-rate sources such as wholesale power sales, long-term power contracts, revenue from transmission and power-related services, investment income and revenue from other fees and charges. Table 3.1 shows forecasted non-rate based revenues for 2013 and 2014 and compares them with the 2012 Financial Plan.

Table 3.1
Non-Rate Based Revenues

$ Millions	2012 Plan	2013	2014	Difference 2013-2012	Difference 2014-2013
Non-Rate Based Revenue					
Net Wholesale Revenue	102.1	90.0	85.0	(12.1)	(5.0)
Power Contracts and Power Marketing	23.9	23.1	23.0	(0.8)	(0.1)
Other Sources	38.7	36.3	38.4	(2.4)	2.1
Total	**164.8**	**149.4**	**146.4**	**(15.3)**	**(3.0)**

3.2 Net Wholesale Revenue

Net revenue from wholesale power sales, also commonly referred to as net wholesale revenue (NWR), is the cash derived from the sale of power that is surplus over system load and other obligations. Table 3.2 lists the planning assumptions for NWR. The annual changes are $12.1 million in 2013 and $5.0 million in 2014, accounting for roughly 37% and 10% of the increase in revenue requirements, respectively.

Table 3.2
Planning Value for Net Wholesale Revenue

$ Millions	2012 Plan	2013	2014	Difference 2013-2012	Difference 2014-2013
Net Wholesale Revenue	102.1	90.0	85.0	(12.1)	(5.0)

In response to the volatility of net wholesale revenue observed in recent years, the City Council established the Rate Stabilization Account (RSA) to buffer NWR. [7] The RSA baseline is the amount against which actual NWR is being tracked and it is the value used in both the development of the budget and the revenue requirements. The RSA Ordinance specified that the RSA baseline would be set using a historical average, which for 2012 was $102.1 million. However, to provide customers with greater rate stability, the 2012 Strategic Plan adopted by the City Council in July 2012 included an initiative to reduce the RSA baseline values. The new methodology calls for the RSA baseline to be gradually lowered, to the point where by 2018 it is likely to be exceeded in three out of four years. This policy change is the reason why the NWR value is declining substantially in 2013 and 2014.

[7] Ordinance 123260, adopted March 2010.

3.3 Power Revenues

Power revenues include revenue received from long term power contracts and revenue received from the sales of excess transmission and auxiliary services (net of purchases). Table 3.3 details the forecasts of these revenue sources.

Table 3.3
Summary of Power Revenues

$ Millions	2012 Plan	2013	2014	Difference 2013-2012	Difference 2014-2013
Power Contracts					
Article 49 Sales to PO County	1.7	1.8	1.8	0.1	0.0
Sales from Priest Rapids	4.9	4.4	4.8	(0.5)	0.4
BPA Credit for South Fork Tolt	3.6	3.3	3.2	(0.3)	(0.1)
BPA Residential Exchange Credit	5.7	5.3	5.3	(0.4)	0.0
Subtotal	**16.0**	**14.9**	**15.2**	**(1.1)**	**0.3**
Power Marketing, Net	0.0	0.0	0.0	0.0	0.0
Transmission Revenue	3.4	4.4	4.4	1.0	0.0
Sale of Lucky Peak Output	0.0	3.0	2.1	3.0	(0.9)
REC Sales	0.6	1.0	1.5	0.4	0.5
Other Sevices, Net	3.9	(0.2)	(0.2)	(4.1)	0.0
Subtotal	**8.0**	**8.2**	**7.8**	**0.3**	**(0.4)**
Total Power Revenues	**23.9**	**23.1**	**23.0**	**(0.8)**	**(0.1)**

Power Contracts
This revenue category includes payments that City Light receives from third parties based on long-term contracts. Similar to the power contracts expenses, the forecast of power contracts revenues is based on the biennial power contracts budget. Power contracts revenue is projected to be around $15 million in both 2013 and 2014, about $1 million lower than was forecast in the 2012 Plan. The primary driver behind this decrease is declining Priest Rapids revenues due to Grant County PUD's increasing load and lower wholesale market prices. The rest of the decrease is due to a lower BPA credit for South Fork Tolt and lower BPA Residential Exchange credit estimated for 2013 and 2014.

Power Marketing, Net
Power Marketing revenues include sales of unused transmission capacity, premiums associated with the sale of Lucky Peak output, Renewable Energy Credits (RECs), as well as purchases and sales of other ancillary services (e.g., reserve energy and capacity, parking and shaping). The forecast matches the expenses and revenues in the 2013-2014 Proposed Budget. The forecast projects net revenues to be around the same level as in the 2012 Plan, though the composition of these revenues has changed. The largest difference is a decrease in the revenues from reserve capacity and reserve energy sales (other services, net) in 2013 and 2014. This is offset by increases to revenue from transmission and sales of Lucky Peak output due to addition of a premium payment that was not assumed in previous years. (See Appendix A for details about Lucky Peak contract.)

3.4 Other Revenue Sources

This category includes cash from a variety of sources such as late payment fees, property rentals, sales of property, investment income, operating fees and grants. Other revenues are generally projected using historical information and inflation. City Light projects that revenue from these sources will decline by $2.4 million in 2013 from the 2012 Plan and will increase by $2.1 million between 2013 and 2014.

As shown in Table 3.4, the primary driver behind the decline in these revenues in 2013 is a projection of $0 in operating fees and grants. The timing and amount of grants to be received is not often known far enough in advance to make precise forecasts more than a few months ahead of time. Another contributing factor is a lower projection of revenues received from the sales of surplus real estate property, which reflects the depressed national and local housing market. An offsetting factor is an increase in the investment income driven by an assumption of increasing interest rates and higher cash balances. The average annual interest rate is assumed to increase from 1.01% to 1.56% from 2012 to 2013 and to 2.11% in 2014.

Table 3.4
Revenue from Other Sources

$ Millions	**2012 Plan**	**2013**	**2014**	**Difference 2013-2012**	**Difference 2014-2013**
Other Sources					
Other Revenue	22.2	22.8	23.3	0.5	0.6
Investments	5.4	7.8	9.7	2.4	1.9
Sale of Property	2.3	1.1	1.1	(1.1)	0.0
Suburban Undergrounding	0.9	1.1	1.3	0.3	0.1
Operating Fees and Grants	3.9	0.0	0.0	(3.9)	0.0
RSA Transfers	(1.1)	(1.4)	(2.0)	(0.3)	(0.5)
Distribution Capacity Charge	0.2	0.2	0.2	0.0	0.0
Green Power Programs	3.1	2.8	2.9	(0.3)	0.1
Power Factor Charges	2.6	2.6	2.6	0.0	0.0
less					
Credits for Transformation	0.3	0.4	0.4	0.0	0.0
Emergency Low-Income Assistance	0.3	0.3	0.3	0.0	0.0
Total	**38.7**	**36.3**	**38.4**	**(2.4)**	**2.1**

Chapter 4: Retail Revenue from Base Rates

The revenue requirement is comprised of retail revenue collected from energy charges, demand charges and base service charges from all customers. Revenue requirements are gross of any rate discounts given to residential customers (which are treated as an expense, as discussed earlier in this document). The adopted revenue requirements are $711.0 million in 2013 and $755.9 million in 2014.

The 2013 and 2014 revenue requirements are predicated on the 4.4% and 5.6% annual rate increases adopted by the 2012 Strategic Plan. Table 4.1 provides a summary of how these rate increases were applied to the forecast of retail sales to produce the adopted revenue requirement. Since the revenue requirement analysis is performed for both years upstream of both the cost allocation and rate design studies, the average rates shown below assume an across–the-board rate increase for all customers. Therefore, the final actual average rates may be slightly different due to allocations and rounding. Information regarding the breakout of City Light's load forecast can be found in the COSACAR.

Table 4.1
Revenue Requirements and Average Retail Rates

	2012 Plan	**2013**	**2014**
Retail Revenue			
Current Rates ($M)	678.9	681.1	686.3
From 2013 Increase ($M)		30.0	30.2
From 2014 Increase ($M)			39.4
Retail Revenue Requirement	**678.9**	**711.0**	**755.9**
Sales to Retail Customers (GWh)	9,631.7	9,654.8	9,746.4
Avg Rates (cents / kWh)			
Current Rates	7.05	7.05	7.04
After 2013 Increase		7.36	7.35
After 2014 Increase			7.76
Annual Rate Increase		4.4%	5.6%

City Light's financial policies require that retail rates be set so that after all operating expenses are paid, there will be enough net revenue remaining to cover the annual debt service by 1.8 times. Table 4.2 shows that the adopted revenue requirements meet City Light's financial policy given the debt service, operating expenses and non-retail operating revenues discussed in Chapters 1 through 3.

Table 4.2
Debt Service Coverage with Adopted Retail Revenue Requirements

$ Millions	2012 Plan	2013	2014	Difference 2013-2012	Difference 2014-2013
Adopted Retail Revenue	678.9	711.0	755.9	32.1	44.9
Operating Expenses	(534.8)	(547.6)	(559.7)	(12.8)	(12.0)
Non-Rate Based Revenue	164.8	149.4	146.4	(15.3)	(3.0)
Amount Available for Coverage	**308.9**	**312.8**	**342.7**	**3.9**	**29.9**
Debt Service	172.8	172.8	189.6	0.0	16.8
Debt Service Coverage Ratio	1.79	1.81	1.81	0.02	(0.00)

Adopted vs. Target Differences
Note that at three significant digits, the debt service coverage ratios shown at the bottom of Table 4.2 are slightly different from 1.8. The target revenue requirement is the retail revenue that provides exactly 1.80 times debt service coverage. However, since the revenue requirement is developed in parallel with the budget, it frequently happens that the final balance of revenues and expenses does not yield exactly 1.80 times debt service coverage.[8] Small differences between the target retail revenue requirement and the adopted retail revenue requirement are considered acceptable so long as the 1.8 times coverage condition is met after rounding to two significant digits.

The revenue requirement in the 2012 Strategic Plan yielded precisely 1.80 times coverage for 2013 and 2014. The 2013 and 2014 Proposed Budget includes as many of the assumptions in the 2012 Strategic Plan as possible. However, some new information was available for debt service, retail load, and power expenses and revenues that differed from the assumptions in the Strategic Plan. These updates were incorporated because it was possible to do so and still comply with City Light's rate-setting financial policy.

Since the change in adopted revenue requirements cannot be fully explained with just operating expenses, non-rate based operating revenues and debt service coverage categories, a fourth category is required to explain the total annual change in the revenue requirement: adopted vs. target difference.

Table 4.3 shows the adopted vs. target revenue requirement differences. In 2013, of the $32.1 million increase in the revenue requirement, $28.2 million can be explained by changes in revenues and expenses discussed in Chapters 1 through 3. The remaining $3.9M is explained by differences in the adopted revenue requirement compared to target revenue requirement, which assumes exactly 1.80 debt service coverage. For example, the 2012 adopted revenue requirement was $2.2 million less than the 2012 target revenue requirement and the 2013 adopted revenue requirement was $1.7 million higher than the 2013 target revenue requirement, resulting in a total change of $3.9 million.

[8] Revenue requirements often need to be frozen before City Light's Budget is finalized to give City policy makers and other stake-holders time to review the resulting impact on the average retail electricity rate.

The change in the adopted-actual difference in 2014 is -0.4 million, which is only a small part of the total $44.9 million change in the 2014 revenue requirement.

Table 4.3
Adopted-Target Differences

$ Millions	2012 Plan	2013	2014	Difference 2013-2012	Difference 2014-2013
Adopted Revenue Requirement	678.9	711.0	755.9	32.1	44.9
Target Revenue Requirement (1.80x)	681.2	709.3	754.6	28.2	45.2
Difference (Adopted - Target)	(2.2)	1.7	1.3	3.9	(0.4)

Chapter 5: Indirect Costs and Proceeds

Indirect expenses and proceeds do not directly impact the revenue requirement in the year in which they occur. Instead, indirect costs influence the amount of long term debt City Light issues in each year and ultimately impact revenue requirements in future years through changes in debt service and debt service coverage. Table 5.1 shows the indirect costs for 2013 and 2014. Note that debt service and the amount available for debt service are discussed in Chapters 1 and 4, respectively.

Table 5.1
Indirect Costs and Proceeds ($M)

$ Millions	**2013**	**2014**
Cash From Operations		
Amount Available For Debt Service	312.8	342.7
Debt Service	172.8	189.6
City Taxes	44.0	46.8
Cash Adjustments	31.5	27.3
Total	**64.4**	**78.9**
Sources of Capital Funding		
Cash from Operations	64.4	78.9
Cash from (to) Cash Balances	8.8	50.9
Bond Proceeds	248.6	187.8
Capital Contributions	26.5	23.4
Total	**348.3**	**341.0**
Capital Expenses		
CIP	286.2	284.3
Deferred O&M	62.1	56.7
Total	**348.3**	**341.0**

5.1 City Taxes

Taxes paid to the City of Seattle are junior to debt service and therefore are not included in the calculation of debt service coverage. Thus, City taxes are an indirect expense. City Light pays the City of Seattle an occupation tax equal to 6.0% of retail revenue and some other sources of outside revenue including other revenue, interest earnings and contributions in aid of construction (CIAC). In addition to the occupation tax, City Light pays the City of Seattle a small business tax. City Taxes increase proportionally with retail revenue.

5.2 Cash Adjustments

There are a number of operating costs and revenues implicit in the amount available for debt service that are accounted for on an accrual basis but the actual cash transactions are lagged. Cash adjustments are made for costs/revenues that are accrued in the previous year but which will be paid/received in the current year, and for costs/revenues that have been accrued in the current year but which will be paid/received in the following year. For example, the retail revenue discussed in Chapter 4 is accrued revenue based on the energy that will be delivered to customers in the current year. City Light will still have to read the meters, bill the customers and collect the payments. Thus, there will be a lag from the time the retail energy is delivered and the revenue is accrued to when the payments are received. Cash adjustments are made to estimate the amount of operating cash flow that will be available for the capital program. These cash flows are referred to as cash from operations, which is treated as a source of capital funds.

In addition to cash lags, there are also certain cash transfers that restrict operating funds, making them ineligible to put towards the capital program. City Light plans on transferring $10 million in operating cash to the restricted bond reserve in both 2013 and 2014 in response to a policy decision that was made to slowly build up a replacement for its current $77.1 million surety bond. The surety bond doesn't expire until 2029 but the credit ratings of its provider (FSA/Assured) are under significant pressure. These $10 million transfers are in addition to bond reserve deposits from bond proceeds, which are needed to meet reserve requirements.

5.3 Capital Expenditures and Funding Sources

Overview

City Light maintains long-range capital improvement and conservation acquisition programs to ensure the availability of adequate supplies of power, to provide a high level of service reliability to its various customer groups, to meet City and State requirements for transportation projects, and to comply with regulatory environmental and mitigation requirements.

Table 5.2 presents a high level overview of all capital expenditures and funding sources. Please see Appendix C for more details about the capital program and its funding sources.

Table 5.2
Total Capital Expenditures and Funding Sources

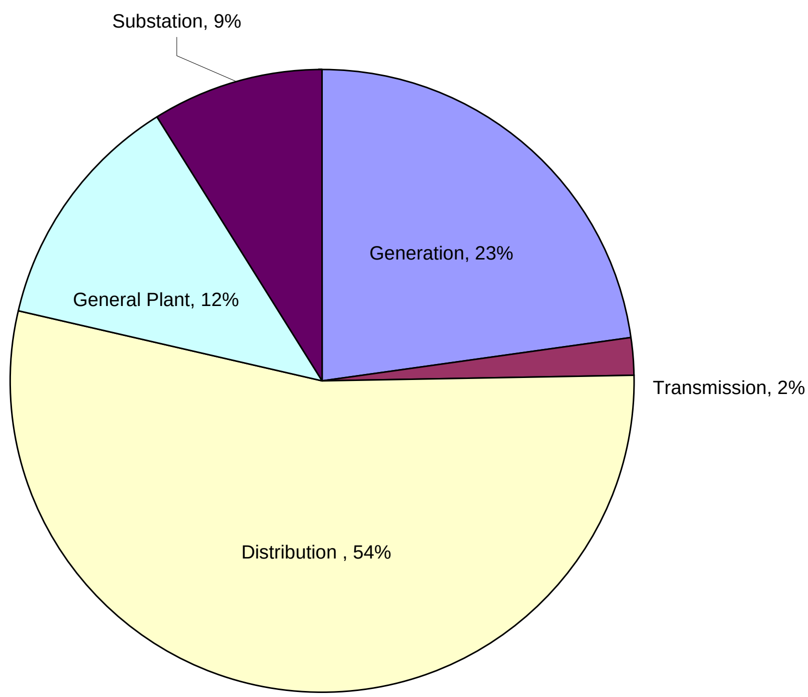
$ Millions	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**Total**
CIP	286.2	284.3	335.3	326.9	249.1	234.8	1,716.6
Conservation	39.6	40.6	43.2	44.2	45.2	46.3	259.1
High Ross Payment Amortization	9.1	9.1	9.1	9.1	9.1	9.1	54.6
Relicensing, Mitigation and Other Costs	13.4	7.0	4.8	2.0	2.0	5.0	34.3
Total Funds Required	**348.3**	**341.0**	**392.4**	**382.2**	**305.4**	**295.2**	**2,064.6**
Cash from Operations	64.4	78.9	86.6	97.1	107.1	107.1	541.2
Cash from Contributions	26.5	23.4	23.5	24.8	38.9	43.2	180.4
Cash from Bond Sale	248.6	187.8	260.2	289.3	211.3	179.8	1,377.1
Cash from Working Capital Account	8.8	50.9	22.1	(29.0)	(51.9)	(34.9)	(34.1)
Total Funds Available	**348.3**	**341.0**	**392.4**	**382.2**	**305.4**	**295.2**	**2,064.6**

Comparison with the last budget cycle and new additions
Similar to the 2011-2016 CIP from the last budget, the largest project is Alaskan Way Viaduct and Seawall Replacement, which relocates City Light infrastructure attached to the existing viaduct. Another large project added this year is the construction of a new north downtown substation and network. In addition, City Light will deploy smart grid technology, with the majority of the expenditures for this project planned in years 2015-2017.

Summary of the CIP and other deferred costs
The financial forecast includes all CIP projects individually documented in the 2013-2014 Proposed Budget. The six-year capital plan expenditures include loadings for benefits, transportation, and administration and general cost allocation, based on the number of labor hours estimated for each project. Based on historical trends, the forecast assumes a 10% under-expenditure in CIP.

CIP expenditures are projected to total $1.7 billion over the six years of the Proposed CIP plan. The forecast classifies CIP expenditures according to functional categories: generation, transmission, distribution, general plant and substation. Figure 5.1 shows a pie chart of these expenditures for the period 2013-2018. Distribution is the largest category, representing 54% of the total CIP expenditures. The second largest is generation expenditures.

Figure 5.1
CIP 2013 – 2018 by Category



In addition to CIP expenditures, City Light also incurs deferred conservation and other deferred costs, which are displayed in Table 5.2. City Light funds conservation investments in the residential, commercial and industrial sectors of the service territory to achieve its long-term energy savings goals. City Light began deferring conservation costs in 1984 per Council Resolution

27372. Since 1986 they have been amortized over twenty years. Amortized costs include only program-specific expenditures that are related to installation of long-lived conservation measures.

Other deferred costs result from the fact that some of the City Light's expenditures do not produce conservation or capital assets, but still relate to activities that have impacts extending beyond the year these payments are made. These include the High Ross Agreement, Superfund cleanup, and activities associated with relicensing City Light dams. These payments are not expensed in the year they are made but are amortized over several years.

Effect on Revenue Requirements
Capital expenditures, deferred conservation and other deferred costs do not affect current period revenue requirements but have a significant effect on the revenue required from customers over time. They affect borrowing requirements and are a major factor in determining the debt issued each year. Debt service payments affect the revenue required from customers in the following years because coverage of debt service is a component of revenue required.

Funding sources
Capital requirements of $2.1 billion from 2013 through 2018 (including $1.7 billion of the CIP and $348.0 million of certain capitalized other costs) are expected to be financed through a combination of cash from operations (net revenues), contributions in aid of construction, reimbursement of costs for transportation-related projects, external conservation funding, and the proceeds of future bonds.

APPENDIX

Appendices List

A. **Power Contracts Details**
B. **Forecast-Budget Crosswalk**
C. **Capital Expenditures and Funding Sources**

An output of the financial reports from City Light's financial forecasting model can be obtained from City Light's Financial Planning Group.

Appendix A: Power Contracts Details

Bonneville Power Administration (BPA)

BPA markets power from the Federal Columbia River Power System (Federal System), comprised of 31 federal hydroelectric projects, several non-federally-owned hydroelectric and thermal projects in the Pacific Northwest region, and various contractual rights, with an expected aggregate output of about 10,813 aMW under average water conditions and about 8,757 aMW under critical conditions. Approximately 7,248 aMW (under critical water conditions) are available for sale at BPA's lowest cost rate that can be sold to preference customers, including City Light, in 2012. The federal hydroelectric projects are built and operated by the United States Bureau of Reclamation (the "Bureau") and the United States Army Corps of Engineers (the "Corps"), and are located primarily in the Columbia River basin. The Federal System currently produces more than 33% of the electric power consumed in the region. BPA's transmission system includes over 15,000 circuit miles of transmission lines, provides about 75% of the Pacific Northwest's high-voltage bulk transmission capacity, and serves as the main power grid for the Pacific Northwest. Its service area covers over 300,000 square miles and has a population of about 12 million. BPA sells electric power at cost-based wholesale rates to more than 125 utility, industrial and governmental customers in the Pacific Northwest. BPA is required by law to give preference to consumer- or publicly-owned utilities and to customers in the Pacific Northwest region in its wholesale power sales.

The Power Sales Agreement with BPA provides for purchases of power by City Light over the 17-year period beginning October 1, 2011. Power is delivered in two products: a shaped block product ("Block"), which is power provided in pre-determined amounts at pre-determined times, and a slice of the system product ("Slice"), which is a proportionate amount of power if, as, and when generated by the Federal System. The power from BPA is delivered in Slice and Block components that are approximately equal on an annual basis. Currently, City Light receives 268 aMW of the Block power, which amount will be reduced by the amount of conserved energy savings purchased by BPA from the utility. Under the Slice product, City Light receives a fixed 3.63323% of the actual output of the Federal System and pays the same percentage of the actual costs of the Federal System. Under critical water conditions, the Slice purchase amounts to 263 aMW over the year. Power available under the Slice product varies with water conditions, federal generating capabilities, and fish and wildlife restoration requirements. City Light may resell output from the Slice product under specified conditions and may use the Slice product to displace its generation.

BPA is required by federal law to recover all of its costs through the rates it charges its customers. Under the current BPA contracts, BPA will conduct a rate case every two years, but the rates are subject to a cost recovery adjustment clause that allows rates to increase during a two-year rate period if certain events occur. There are many factors that have impacted and could impact BPA's cost of service and rates, including federal legislation, BPA's obligations regarding its outstanding federal debt, number of customers, water conditions, fish and other environmental regulations, capital needs of the Federal System, outcome of various litigation, regional transmission issues, natural gas prices, and the economy.

Priest Rapids

Under two agreements effective through 2052, City Light purchases a portion of the output of the Priest Rapids Project, which is owned and operated by Public Utility District No. 2 of Grant County

(“Grant PUD”). The Priest Rapids Project, which is comprised of two dams, Priest Rapids and Wanapum, both located on the Columbia River, has an installed capacity of 1,893 MW. As of November 2009, City Light is obligated to purchase 6.14% of the output of both Priest Rapids dam (855 aMW total) and Wanapum dam (1,038 aMW total) available after Grant PUD meets its retail load. As Grant PUD’s retail load increases, less electrical energy is available for City Light; City Light currently receives only about 2 aMW from these contracts. The Department also receives a portion of the revenues from an auction of 30% of the project power. Under the contracts, the Department is responsible for its percentage share of the costs of the Priest Rapids project.

Grand Coulee
City Light, in conjunction with the City of Tacoma Department of Public Utilities, Light Division (“Tacoma Power”), has power purchase agreements with three Columbia Basin irrigation districts for the acquisition of power from five hydroelectric plants under 40-year contracts expiring between 2022 and 2027. These plants, which utilize water released during the irrigation season, are located along irrigation canals in eastern Washington. The plants generate power only in the summer and thus have no winter peak capability. Plant output and costs are shared equally between the Department and Tacoma Power.

High Ross
In 1984, an agreement was reached between the Province of British Columbia and the City under which British Columbia provides City Light power equivalent to that which would have resulted from an addition to the height of City Light’s Ross Dam on the Skagit River that would have expanded the area flooded in British Columbia. The agreement was ratified through a treaty between Canada and the United States the same year. The power is to be received for 80 years, and delivery of power began in 1986. City Light will make annual payments to British Columbia of $21.8 million through 2020, which represents the estimated debt service costs City Light would have incurred had the addition been constructed. City Light also pays British Columbia the equivalent of the operation and maintenance costs which would have been incurred if the High Ross project had been built. The payments are charged to expense over a period of 50 years through 2035.

Lucky Peak
The Lucky Peak Hydroelectric Power Plant was developed by three Idaho irrigation districts and one Oregon irrigation district (the “Districts”) and began operation in 1988. Its FERC license expires in 2030. The plant is located on the Boise River, approximately ten miles southeast of Boise, Idaho, at the Lucky Peak Dam and Reservoir. The nameplate capacity is 113 MW, but the plant operates only during the irrigation season, so it provides no peak capacity during the Department’s winter peak period.

In 1984, the Department entered into a power purchase and sales contract with the Districts under which the Department will purchase all power generated by the Lucky Peak Project, in exchange for payment of costs associated with the plant and royalty payments to the Districts. The Department also signed a transmission services agreement with Idaho Power Company (“Idaho Power”) to provide for transmission of power from the Lucky Peak Project to a point of interconnection with the BPA transmission system.

City Light has sold the actual net output of the Lucky Peak plant for the last several years. The output has been sold, again, for calendar years 2012 and 2013. In exchange for the actual output, the purchaser (Cargill) will deliver to City Light 100 aMW flat in January and February and 50 MW flat in March. Additionally, the purchaser will deliver 50 aMW during light load hours (LLH) in each month of the fourth quarter. The exchange energy is delivered to the Mid-C trading hub.

Stateline Wind Project
An agreement with J.P. Morgan Ventures Energy Corp. provides for the City Light purchase of wind-generated power and associated renewable energy credits from the Stateline Wind Project in eastern Washington and Oregon. City Light purchases a percentage of the output from the Stateline Wind Project. The contract terms are from July 1, 2004, through December 31, 2021.
Through the end of the contract in 2021, the Department receives wind power with a maximum delivery rate of 175 MW per hour.

City Light also entered into a related ten-year agreement with PacifiCorp to purchase integration and exchange services for all of City Light's 175 aMW share of the Stateline Wind Project output. Under this agreement, PacifiCorp delivers the Department's share of the Stateline Wind Project output to the Mid-Columbia market hub two months after it is generated. The integration and exchange agreement with PacifiCorp terminates at the end of 2021.

Small Renewables

SMUD: In 2007 City Light began a seasonal exchange with Sacramento (CA) Municipal Utility District (SMUD), in which City Light provides scheduling and delivery services for up to 15 aMW of power at the California-Oregon border that SMUD purchased from a renewable resource in the Pacific Northwest, the Sierra Pacific Industries Burlington Biomass Facility, which burns wood waste and produces electrical energy. The Department receives up to 25 MW of winter energy in payment for such services, and purchases from Sierra Pacific Industries all of the renewable energy and environmental attributes associated with the resource in excess of 15 MW. The contract expires in 2017.

Columbia Ridge Landfill Gas: In December 2009, City Light began taking delivery of 6 aMW per year and associated renewable energy credits (RECs) from the Columbia Ridge Landfill Gas project in Arlington, Oregon. The plant burns methane produced by the decomposition of solid waste in the landfill and has 6.4 MW of generation capacity. The City sends its solid waste to the landfill. Waste Management Renewable Energy (WMRE) is the developer, owner and operator of the project. The contract has a 20-year term, with specific prices and escalation rates. City Light redirected some transmission paths, and has firm transmission for project output to City Light's retail load. In addition, City Light is in the process of negotiating with WMRE a separate contract to buy an additional 6 aMW per year from this plant starting as early as October 2013.

King County West Point Treatment Plant: In 2010, City Light executed a power purchase agreement with King County for the output of a proposed cogeneration plant at the West Point Wastewater Treatment Facility in Seattle. As of February 2012, the County has produced test power and will begin commercial operation shortly. The 4.6 MW plant is expected to provide 2 aMW of electrical energy and associated renewable energy credits (RECs). The contract has specific prices and annual escalation and extends for 20 years after commercial operations begin.

Appendix B: Forecast-Budget Crosswalk

This appendix provides detail on the relationship between the costs in the budget and the financial forecast. The two methods of looking at future costs treat these costs differently because they have two different objectives. Primarily, the budget sets a spending authority, while the financial forecast estimates expenses for future compliance with City Light's financial policies. In many instances the budget and the financial forecast are the same. However, there are a number of expense categories where the two have different definitions and or assumed values of expenses. The goal of this appendix is to explain how and why the two methods are different.

Summary

Table B.1 provides a high-level comparison of the expenses in the budget and the forecast. The two largest differences are the 10% CIP under-expenditure assumption and the treatment of short term purchased power. For example, in 2013 the $101 million difference in expenses can largely be explained by the $31.8M from the 10% CIP under-expenditure assumption and $52 million from netting out short term purchase sales from revenue in the forecast.

Table B.1
Forecast-Budget Crosswalk Summary

$ Millions	**2013 Budget**	**2014 Budget**	**2013 Forecast**	**2014 Forecast**	**2013 Diff**	**2014 Diff**
Operating Expenses						
Total Non-Power O&M	$350.3	$354.2	$225.9	$227.3	($124.4)	($126.9)
Long Term Purchased Power	277.3	287.1	269.0	276.6	(8.3)	(10.5)
Short Term Purchased Power	52.0	55.6	-	-	(52.0)	(55.6)
Taxes	81.6	86.2	81.3	86.2	(0.2)	0.0
Debt Service	179.7	196.5	172.8	189.6	(6.8)	(6.8)
Capitalized Expenses						
CIP	283.0	304.9	286.2	284.3	3.2	(20.6)
Deferred O&M	46.6	47.4	62.1	56.7	15.5	9.3
Adjust for Labor Loadings	(71.7)	(70.1)	-	-	71.7	70.1
Total Expenses, less Capital Loadings	**$1,198.8**	**$1,261.7**	**$1,097.4**	**$1,120.7**	**($101.3)**	**($140.9)**

Notes	
Total Non-Power O&M	See Table B.5 for detail
LT Purchased Power	See Table B.2 for detail
Short Term Purchased Power	Net wholesale revenue is forecast as a single value, but must be artificially separated into gross purchases and sales to create the short term purchased power budget. Similarly, power marketing expense is netted from revenue for forecast purposes,.
Taxes	The budget uses paid taxes, while the forecast uses accrued taxes. In addition, the budget includes taxes on suburban undergrounding revenue, which is included in deferred O&M in the financial forecast
Debt Service	The forecast is net of $5.44M in federal interest subsidies while budget uses gross debt service. In addition, the budget includes $1.38M of issue costs while the forecast does not include issue costs in debt service; instead these are netted from bond proceeds.
CIP and Deferred O&M	See Table B.6 for detail
Ajust for Labor Loadings	In the budget, both the CIP budget and O&M budget include an estimate of labor loadings. Subtracting them avoids double counting when aggregating the CIP and O&M budget to compare the total expenses with the forecast.

Table B.2
Power Contracts Forecast-Budget Crosswalk

$ Millions	2013 Budget	2014 Budget	2013 Forecast	2014 Forecast	2013 Diff	2014 Diff	Notes
Long-Term Purchased Power	**238.7**	**246.2**	**222.1**	**228.9**	**(16.6)**	**(17.3)**	
High Ross	22.2	22.2	13.1	13.1	(9.1)	(9.1)	$9.1 million is deferred in the financial forecast
BPA costs	162.9	167.2	158.6	162.3	(4.3)	(4.9)	Forecast uses values consistent with the 2012 Strategic Plan. The budget includes a $4 M buffer for a possible CRAC, and assumes higher inflation for Q4 2013 and 2014.
Green-up RECs	1.4	1.5	0.0	0.0	(1.4)	(1.5)	Forecast categorizes as production non-power O&M
Upstream Storage Benefit	1.8	1.8	0.0	0.0	(1.8)	(1.8)	Forecast includes this in water for power
Wheeling	**38.6**	**40.9**	**36.8**	**37.5**	**(1.7)**	**(3.4)**	
Lucky Peak	0.0	2.4	0.0	0.0	0.0	(2.4)	Forecast assumes that when a contract is signed for the 2014 Lucky Peak exchange, the buyer will pay transmission costs directly to Idaho Power, similar to 2012-2013 contract terms.
AC Intertie Ownership	1.9	1.1	0.0	0.0	(1.9)	(1.1)	Forecast categorizes as production non-power O&M
Other Wheeling	0.1	0.1	0.0	0.0	(0.1)	(0.1)	Buffer for misc transmission costs, not included in forecast
Short Term Wheeling			0.2	0.2	0.2	0.2	Included in ST Purchased Power in budget
Water for Power	**0.0**	**0.0**	**10.1**	**10.2**	**10.1**	**10.2**	Not a budget category; only found in the forecast
Upstream Storage Benefit	0.0	0.0	1.8	1.8	1.8	1.8	Forecast includes this in water for power
FERC Fees	0.0	0.0	8.1	8.3	8.1	8.3	Budgeted in production non-power O&M. Forecast FERC fee values are consistent with the 2012 Strategic Plan.
WA Dept of Ecology	0.0	0.0	0.2	0.2	0.2	0.2	Budgeted in production non-power O&M
TOTAL Power Contract Costs	**277.3**	**287.1**	**269.0**	**276.6**	**(8.2)**	**(10.5)**	

Non-Power O&M

The following three tables help explain the annual changes in Non-Power O&M in the RRA.

- Table B.3 presents the annual changes that were made to the budget.
- Table B.4 provides more detail on the specific new initiatives (i.e., BIPs)
- Table B.5 lists the adjustments that are made to the O&M budget to get to the O&M forecast for the RRA.

Table B.3
2013 and 2014 Non-Power O&M Budget Changes

2013 Proposed O&M Budget ($M)	2012 Adopted	Annual Changes from 2012 Adopted: Inflation	BIPs 2013	Technical BIPs 2013	2013 Proposed Budget
Budget BCL					
Office of Superintendent	$ 2.92	$ 0.08	$ 0.11	$ 0.01	$ 3.12
Human Resources	$ 6.79	$ 0.18	$ 2.42	$ (0.00)	$ 9.38
General Expenses	$ 77.57	$ 5.08	$ (0.55)	$ 4.15	$ 86.25
Compliance and Security	$ 2.83	$ 0.07	$ 0.27	$ (0.00)	$ 3.16
Power Supply O&M	$ 62.45	$ 1.70	$ 0.28	$ (13.43)	$ 51.00
Conservation Resources and Environmental Affairs	$ 57.76	$ 1.34	$ 0.43	$ 0.31	$ 59.84
Distribution Services	$ 70.79	$ 2.02	$ 0.06	$ 0.91	$ 73.79
Customer Services	$ 26.85	$ 0.74	$ 0.82	$ (0.87)	$ 27.54
Financial Services	$ 28.99	$ 0.70	$ 6.49	$ 0.03	$ 36.21
Total	**$ 336.94**	**$ 11.91**	**$ 10.33**	**$ (8.90)**	**$ 350.28**

2014 Proposed O&M Budget ($M)	2012 Adopted	Annual Changes from 2012 Adopted: Inflation (2012-2014)	BIPs 2014	Technical BIPs 2014	2014 Proposed Budget
Budget BCL					
Office of Superintendent	$ 2.92	$ 0.14	$ 0.11	$ 0.02	$ 3.20
Human Resources	$ 6.79	$ 0.32	$ 2.01	$ 0.02	$ 9.14
General Expenses	$ 77.57	$ 9.83	$ (2.31)	$ 1.62	$ 86.71
Compliance and Security	$ 2.83	$ 0.13	$ 0.48	$ 0.00	$ 3.44
Power Supply O&M	$ 62.45	$ 3.12	$ (0.28)	$ (13.74)	$ 51.55
Conservation Resources and Environmental Affairs	$ 57.76	$ 2.69	$ 0.58	$ 0.51	$ 61.54
Distribution Services	$ 70.79	$ 3.54	$ (1.92)	$ 1.54	$ 73.94
Customer Services	$ 26.85	$ 1.32	$ 0.83	$ (0.80)	$ 28.20
Financial Services	$ 28.99	$ 1.36	$ 6.14	$ (0.00)	$ 36.48
Total	**$ 336.94**	**$ 22.45**	**$ 5.65**	**$ (10.84)**	**$ 354.20**

Table B.4
2013 and 2014 Budget Issue Paper Detail

$ Millions		BIPS	BIPS
BCL Name	**BIP Title**	**2013**	**2014**
Office of Superintendent	Attract and Retain Workforce	$ 0.10	$ 0.10
	Workforce Development - Utility Training and Development Program	0.01	0.01
Office of Superintendent Total		0.11	0.11
Human Resources	Safe Work Environment	1.27	0.86
	Attract and Retain Workforce	0.14	0.14
	Workforce Development - Utility Training and Development Program	1.01	1.01
Human Resources Total		2.42	2.01
General Expenses	Regional and Industry Leadership	0.07	0.08
	Safe Work Environment	-0.66	-1.21
	Attract and Retain Workforce	0.03	0.03
	Workforce Development - Utility Training and Development Program	0.03	0.03
	Establish Internal Audit/Management Review Group	0.16	0.16
	Insurance Policy for Generation Facilities	0.51	0.52
	Compliance Tracking System and Compliance Program Standardization	0.08	0.09
	Integrated Geospatial Information System (GIS)	0.09	0.00
	IT Disaster Recovery Program	0.04	0.04
	Implement IT Security Upgrades	0.04	0.04
	Efficiency Projects	-0.93	-2.07
General Expenses Total		-0.55	-2.31
Compliance and Security	Attract and Retain Workforce	0.04	0.04
	Workforce Development - Utility Training and Development Program	0.01	0.01
	Compliance Tracking System and Compliance Program Standardization	0.23	0.44
Compliance and Security Total		0.27	0.48
Power Supply O&M	Improve Hydro System Optimization and Generator Availability	0.31	0.52
	Regional and Industry Leadership	0.24	0.24
	Attract and Retain Workforce	0.38	0.38
	Workforce Development - Utility Training and Development Program	0.25	0.25
	Equipment Servicer Adds	0.00	0.00
	Efficiency Projects	-0.89	-1.67
Power Supply O&M Total		0.28	-0.28
Conservation Resources and Environmental Affairs O&M	Workforce Development - Utility Training and Development Program	0.08	0.08
	Climate Research	0.22	0.23
	Reduce Environmental Liability	0.13	0.27
Conservation Resources and Environmental Affairs O&M Total		0.43	0.58
Distribution Services	Workforce Development - Utility Training and Development Program	0.55	0.55
	Integrated Geospatial Information System (GIS)	0.32	0.00
	Efficiency Projects	-1.07	-3.00
	Standards and Compatible Units	0.26	0.52
Distribution Services Total		0.06	-1.92
Customer Services	Attract and Retain Workforce	0.34	0.34
	Workforce Development - Utility Training and Development Program	0.21	0.21
	Comprehensive Low Income Assistance Program	0.43	0.44
	Efficiency Projects	-0.16	-0.16
Customer Services Total		0.82	0.83
Financial Services - O&M	Attract and Retain Workforce	0.22	0.22
	Workforce Development - Utility Training and Development Program	0.14	0.14
	Performance Based Reporting	1.42	0.78
	Establish Internal Audit/Management Review Group	0.66	0.68
	Project Management Quality Improvements	0.65	0.45
	Benchmarking Performance	0.28	0.29
	Restore IT Software Maintenance Budget	3.16	3.23
	IT Disaster Recovery Program	0.10	0.51
	Enterprise Document Management System	0.05	0.04
	Efficiency Projects	-0.20	-0.21
Financial Services - O&M Total		6.49	6.14
TOTAL		**10.33**	**5.65**

Table B.5
2013 and 2014 Non-Power O&M Budget Forecast Crosswalk Detail

City Light Budget to Forecast O&M Cross-Walk

		$ Millions	2012 Adopted	2013 Proposed	2014 Proposed
A		**Total Non-Power O&M in Budget**	336.94	350.28	354.20
B	less	Deferred O&M in Non-Power O&M Budget	48.53	46.58	47.37
C	less	FERC Fees in Power Supply Budget	8.12	7.84	7.95
D	less	Capital Loadings	65.38	71.65	70.07
E	add	REC and Intertie Expense in Power Supply Budget	2.23	3.29	3.74
F	add	Difference in Forecast-Budget Liability Payments	1.06	-	-
G	add	O&M Budget Adjustments	2.33	(1.59)	(5.26)
H	equals	**Non-Power O&M for Financial Forecast**	**220.52**	**225.91**	**227.30**
			-	-	-
		Non Power O&M in 2013-2014 Adopted Rate Study	220.52	225.91	227.30
		Difference from Budget	-	-	-

Notes

General	The structure of the O&M categories used in the financial forecast are based on FERC accounting standards, which are used to track financial actuals and calculate financial metrics such as debt service coverage. This is the fundamental reason why the O&M in the budget needs to be adjusted to meet the structure of the financial forecast.
A	This is the total non-power O&M in the budget, and excludes purchased power, taxes, debt service and CIP.
B	Deferred O&M is a capitalized expense in the financial forecast and not considered part of Non-Power O&M. The value of deferred O&M in the financial forecast is the projected cash flow associated with the planned levels of deferred O&M in the budget.
C	FERC fees are budgeted in the Power Supply BCL and therefore are considered non-power O&M in the budget. However, they are treated as purchased power in the financial forecast and therefore are not considered non-power O&M in the forecast
D	Capital loadings are the portion of non-power O&M that is forecasted to be overhead associated with the planned levels of CIP and Deferred O&M. Overhead expenses include paid time off, fringe benefits, material handling, transportation use, shop handling and A&G. Overhead expenses are capitalized and not included in non-power O&M in the forecast
E	REC purchases and intertie O&M are budgeted in long term purchased power and wheeling. However, they are production non-power O&M in the forecast. See Table B.2 for more detail.
F	Liability payments include toxic cleanup and other legal claims that City Light is required to pay. A dicretionary adjustment was made in 2012 to make the forecast more conservative than the budget.
G	These are cash flow adjustments that include assumptions on underexpenditures and carry forwards.
H	On a "balanced crosswalk" this value should equal the sum of the Production through Administration lines on FPU's Cash Flow Table.

Table B.6
CIP and Deferred O&M Crosswalk between Budget and Forecast

$ Millions	2013 Budget	2014 Budget	2013 Forecast	2014 Forecast	2013 Diff	2014 Diff	Notes
CIP	**283.0**	**304.9**	**286.2**	**284.3**	**3.2**	**(20.6)**	
Carry Forwards	0.0	0.0	25.5	11.3	25.5	11.3	Expenditures carried forward from the previous year budget.
AFUDC*	8.4	7.8	0.0	0.0	(8.4)	(7.8)	No AFUDC is assumed in the CIP expenses in the financial forecast
Cash Flow Adjustments	0.0	0.0	17.9	7.5	17.9	7.5	Adjustments for differences in cash spending vs. budgeting for selected projects
Underexpenditure Assumption	0.0	0.0	(31.8)	(31.6)	(31.8)	(31.6)	Forecast assumes only 90% of CIP will be spent based on historical experience.
Deferred O&M	**46.6**	**47.4**	**62.1**	**56.7**	**15.5**	**9.3**	
Programmatic Conservation	36.2	37.0	39.6	40.6	3.4	3.6	Forecast includes estimated labor loadings, and also incorporates payment lags for multi-year projects.
Toxic Cleanup Expenses	10.2	10.2	13.0	6.7	2.8	(3.5)	Forecast estimates actual expenditures and includes cash flow adjustments for expenditures budgeted in prior years.
Hydro Project Relicensing	0.1	0.1	0.2	0.2	0.1	0.1	Forecast includes estimate of labor loadings.
Other Deferred O&M	0.0	0.1	0.0	0.0	(0.0)	(0.1)	Misc items not included in the forecast.
Deferred High Ross	0.0	0.0	9.1	9.1	9.1	9.1	$9.1M of High Ross expenditures is deferred every year.
Deferred Taxes	0.0	0.0	0.2	0.1	0.2	0.1	Taxes paid on revenue from suburban undergrounding are deferred. These are included in the O&M tax budget.

* AFUDC is accounting terminology for capitalizing the interest costs that are part of the cost of acquiring certain assets. The financial forecast does not include these costs as part of capital expenses but includes estimates of AFUDC as part of accrued interest expense.

Appendix C: Capital Expenditures and Funding Sources

Capital Expenditures

The City's biennial budget process approves the annual funding levels for both the CIP and the conservation resource acquisition plan. Expenditures for all new and existing projects are reviewed and project details for each capital project are kept in City Light's ESPro budget system. Capital projects become part of the City Light CIP proposal after an identification, selection and prioritization process in which project justification, costs and benefits are closely examined. City Light has implemented a more rigorous utility-wide prioritization process over the last several years, requiring that new initiatives and existing projects with major changes in scope or budget provide a business case and economic analysis that justifies funding for the project. The economic analysis includes a discussion of all benefits and costs, including customer service, legal and technical considerations, environmental and risk impacts. Every two years, the Mayor and the City Council, as part of the City's biennial budget process, review proposed capital expenditures for the budget period, approving expenditures for the first year and endorsing expenditures for the second year.

Table C.1 shows Proposed 2013-2018 CIP and other deferred costs and their funding sources.

Generation. Generation plant includes facilities used to produce electricity. Typical assets would be reservoirs, dams, waterways, waterwheels, turbines, generators and accessory electrical equipment. Generation expenditures are projected to total $390.7 million during the six-year planning period, averaging about $65.1 million per year and representing about 23% of planned capital expenditures for that period. A large percentage of generation investment is dedicated to core utility functions that maintain or add to generation infrastructure and insure system reliability and power availability to customers. SCL continuously invests in its generator and turbine runner rebuild programs ($67.1 million) and improvements at Skagit ($72.3 million) and Boundary Plants ($107.7 million). A large portion of funds provides for environmental mitigation requirements primarily related to federal relicensing of the Boundary Project ($112.5 million) and Endangered Species Act mitigation ($6.0 million).

Transmission. Transmission plant includes poles, towers and conductors used to carry electricity from generation facilities to substations. Transmission expenditures are projected to total $33.4 million during the six-year planning period, averaging about $5.6 million per year and representing about 2% of planned expenditures for that period. The transmission reliability project ($14.6 million) supports engineering, construction, and other work necessary to improve or maintain the reliability of the overhead or underground transmission system. Reliability projects include line rebuilds, new lines to enhance reliability of a substation, new line configurations to improve operation, and relocations required to maintain the transmission system. A new addition is the Denny Substation Transmission Lines project ($15.7 million), which designs and constructs transmission lines to support the new North Downtown Substation. Investments are also needed to relocate transmission facilities at the request of other agencies ($2.9 million). Relocations are necessitated by road realignments, construction of facilities, regional upgrades, and changes in lighting.

Distribution. Distribution plant includes poles, wires and cables, transformers, manholes, vaults, ducts, and other electrical equipment and infrastructure needed to deliver power from the substation to the customer connection at home or business in both network and non-network areas. The Department plans to spend about $925.8 million from 2013 to 2018 on distribution system improvements and additions, averaging $154.3 million per year and representing about 54% of total CIP expenditures. Significant expenditures are required for the following purposes:
(i) constructing new and enlarged overhead and underground service connections within the Department's service territory,
(ii) relocating infrastructure and providing capacity related to a number of large local transportation and regional transit projects, including the Alaskan Way Viaduct and the Seawall Replacement,
(iii) building or re-conductoring line segments, adding cables for increased customer loads, installing new feeders, and adding underground facilities to match changing service demands,
(iv) building lines to connect customers to the new North Downtown substation, and
(v) investing in Smart Grid technology.

General Plant. General plant includes non-electrical system assets including buildings and facilities, such as the North and South Service Centers, and investments in office-related computer equipment, information and communications systems, furniture, and mobile equipment. Programmed expenditures of $212.7 million provide for general plant improvements and/or replacement over the 2013-2018 period, averaging about $35.5 million per year and representing about 12% of total capital expenditures over the six-year period. The Department plans to fund major replacement and improvement of its information technology infrastructure ($79.9 million), replace and expand its heavy-duty mobile equipment fleet ($29.7 million), and continue installation and configuration of an asset management system ($11.0 million). Investments in communications systems ($18.6 million) are also scheduled and provide for improvements in distribution area communications networks and transmission and generation radio systems.

Substations. Substation expenditures are projected to total $154.0 million during the six-year planning period, averaging about $25.7 million per year and representing about 9% of planned expenditures for that period. The major project is a design and construction of a new North Downtown Substation. Other projects include the replacement of existing substation equipment, including transformers and breakers to maintain reliability and to increase capacity to provide for load growth.

Table C.1
Total Capital Expenditures and Funding Sources

	2013	2014	2015	2016	2017	2018	Total
Generation							
Skagit Plant Improvements	$ 14.3	$ 15.5	$ 11.9	$ 12.6	$ 9.9	$ 8.1	$ 72.3
Generators and Turbine Runners	25.5	8.5	8.3	11.1	6.7	6.8	67.1
Boundary Plant Improvments	6.6	12.3	20.0	28.6	20.2	20.0	107.7
Environmental Mitigation	15.5	12.0	23.2	32.5	13.4	22.4	119.0
Other Generation	3.5	3.6	5.2	3.4	5.0	3.8	24.5
Subtotal	$ 65.4	$ 52.0	$ 68.7	$ 88.3	$ 55.2	$ 61.1	$ 390.7
Transmission	$ 3.8	$ 3.2	$ 3.9	$ 7.9	$ 4.0	$ 10.6	$ 33.4
Distribution							
Service Connections	$ 25.4	$ 26.3	$ 27.9	$ 28.0	$ 26.8	$ 27.3	$ 161.6
Transportation Related	34.3	34.5	30.2	12.9	9.7	9.9	131.4
Capacity Additions	22.9	24.4	27.3	28.3	24.4	23.9	151.2
Pole Replacements	8.8	6.3	8.0	9.2	9.3	9.5	51.1
Reliability	18.2	20.8	21.5	19.1	21.4	22.0	123.1
Street and Floodlights	7.3	7.6	8.7	8.0	8.2	8.4	48.2
Underground Projects	7.0	4.7	3.8	3.9	4.0	4.1	27.3
Other Distribution	4.2	5.4	14.4	17.5	9.6	9.9	61.1
Smart Grid	1.2	2.8	28.4	27.2	26.8	5.0	91.4
26 kV Conversion	2.1	2.8	2.8	1.9	1.6	1.8	13.0
Suburban Undergrounding	8.5	0.8	-	-	-	-	9.2
North Downtown Network	2.2	4.4	11.5	21.4	8.0	4.1	51.6
Mobile Workforce	-	-	1.4	2.5	0.9	0.8	5.7
Subtotal	$ 142.1	$ 140.8	$ 185.9	$ 179.7	$ 150.6	$ 126.6	$ 925.8
General Plant							
Information Technology	$ 17.5	$ 26.3	$ 16.5	$ 11.3	$ 4.5	$ 3.8	$ 79.9
Vehicle Replacement	6.9	7.6	4.1	4.3	3.0	3.9	29.7
Other General Plant	18.9	17.3	10.6	9.2	9.2	8.5	73.6
Asset Management	4.8	3.1	1.7	0.8	0.3	0.3	11.0
Communications	5.6	3.0	2.4	2.7	2.3	2.5	18.6
Subtotal	$ 53.7	$ 57.4	$ 35.2	$ 28.3	$ 19.2	$ 19.0	$ 212.7
Substation							
North Downtown Substation	$ 4.1	$ 14.7	$ 22.1	$ 5.3	$ 0.8	$ -	$ 47.1
Other Substation	17.1	16.2	19.5	17.4	19.2	17.5	106.9
Subtotal	$ 21.2	$ 30.9	$ 41.6	$ 22.8	$ 20.0	$ 17.5	$ 154.0
Total CIP	$ 286.2	$ 284.3	$ 335.3	$ 326.9	$ 249.1	$ 234.8	$ 1,716.5
Conservation	$ 39.6	$ 40.6	$ 43.2	$ 44.2	$ 45.2	$ 46.3	$ 259.1
High Ross Payment Amortization	9.1	9.1	9.1	9.1	9.1	9.1	54.6
Relicensing, Mitigation and Other Costs	13.4	7.0	4.8	2.0	2.0	5.0	34.3
Total Funds Required	$ 348.3	$ 341.0	$ 392.4	$ 382.2	$ 305.4	$ 295.2	$ 2,064.5
Sources of Funds							
Cash from Operations	$ 64.4	$ 78.9	$ 86.6	$ 97.1	$ 107.1	$ 107.1	$ 541.2
Cash from Contributions	26.5	23.4	23.5	24.8	38.9	43.2	180.4
Cash from Bond Sale	248.6	187.8	260.2	289.3	211.3	179.8	1,377.1
Cash from Working Capital Account	8.8	50.9	22.1	(29.0)	(51.9)	(34.9)	(34.1)
Total Funds Available	$ 348.3	$ 341.0	$ 392.4	$ 382.2	$ 305.4	$ 295.2	$ 2,064.6

Conservation. Conservation resource programs offer financial incentives (such as rebates, discounts and loans) to customers who can produce energy savings by installing approved energy-saving equipment or weatherization measures or by designing a building to exceed energy code requirements. Program costs include program administration, audits and inspections, and the costs of designing and installing energy savings measures. The conservation forecast for 2013 through 2018 maintains the annual energy savings to be achieved at 14.0 aMW, and the expenditure forecast reflects this increase.

High Ross Payment Amortization. In setting rates for the 2000-2003 period, the City Council directed the Department to amortize the $21.8 million capital portion of the annual payment to B.C. Hydro under the High Ross Agreement through 2035. The Department pays B.C. Hydro $21.8 million each year from 2000 through the final capital payment in 2020, $9.1 million of the annual payment is deferred, and $12.7 million is recognized as an expense. From 2021 through 2035, the remaining balance of deferred costs will be amortized. The deferred portion of the payments to B.C. Hydro is capitalized and therefore is treated as a component of capital requirements.

Relicensing, Mitigation and Other Costs. In addition to making capital expenditures for environmental mitigation as part of its CIP, the Department pays in the year incurred but for planning purposes defers and capitalizes certain operations and maintenance expenditures for environmental mitigation. Deferred expenditures are projected to be $34.3 million over the six-year planning period. These deferred O&M expenditures are for mitigation measures similar to those included in the CIP; however, they differ from those in the CIP because they are for measures on land or structures belonging to entities other than the Department and involve payments to the owners. Recipients of these payments include a variety of nonprofit organizations and governmental agencies with which the Department has entered into contracts for environmental mitigation pursuant to the terms of relicensing settlement agreements. Other deferred costs include debt expense and studies related to future capital projects.

Funding Sources

Capital requirements of $2.1 billion from 2013 through 2018 (including $1.7 billion of the CIP and $348.0 million of certain capitalized other costs) are expected to be financed through a combination of cash from operations (net revenues), contributions in aid of construction, reimbursement of costs for transportation-related projects, external conservation funding, and the proceeds of future bonds.

Cash from Operations. Cash from Operations is the amount of cash inflow from current operating revenues that remains after all cash outflows for current operating expenditures including debt service and all taxes. The higher the amount of Cash from Operations available for capital expenditures, the lower the amount the utility needs to borrow to fund capital expenditures by issuing long-term debt.

Cash from Contributions. Cash from Contributions is a source of cash that cannot be counted on to pay debt service expenses. This category of cash, given planned expenses, affects the amount borrowed and, thereby, affects future debt service requirements and future rates. Table C.2 displays the 2013-2014 forecast of funding from contributions, which include contributions in aid of construction (CIAC), grants and fees for specific projects (i.e. Sound Transit Light Rail) and BPA funding for conservation.

Table C.2
Cash from Contributions

$ millions	2012 Plan	2013 Forecast	2014 Forecast	Difference 2013 - 2012	Difference 2014 - 2013
Cash from Contributions					
Capital Fees and Grants	$0.5	$0.8	$1.0	$0.3	$0.2
Contributions in Aid - Cash	24.9	20.3	22.4	(4.6)	2.0
BPA Payments for Conservation	-	5.4	-	5.4	(5.4)
Total	$25.5	$26.5	$23.4	$1.1	($3.1)

Cash from Bond Sale. Cash from Bond Sale is not available to pay debt service costs and, therefore, does not affect the revenue requirements for the current rate year. The amounts borrowed, of course, affect future debt service requirements and future rates.

Cash from Working Capital Account. These are funds earned in previous years that are spent in the current year or funds earned in the current year that are carried forward to future years.